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INTERNATIONAL SMART GRID ACTION NETWORK

## Power Transmission & Distribution Systems

# Hydrogen sector impact on power grid: production/storage/transport

## Discussion Paper

**ISGAN WG6 Transmission & Distribution**

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## Nomenclature or List of Acronyms

| | |
|---|---|
| ACER | Agency for the Cooperation of Energy Regulators |
| AEL | Alkaline Electrolysis |
| AEMEL | Anion Exchange Membrane Electrolysis |
| AFIR | Alternative Fuels Infrastructure Regulation |
| CCfD | Carbon Contracts for Difference |
| CCGT | Combined Cycle Gas Turbine |
| CCS | Carbon Capture and Sequestration |
| CCUS | Carbon Capture and Underground Storage |
| CHP | Combined Heat and Power |
| DS | Distribution System |
| DSO | Distribution System Operator |
| EC | European Commission |
| EHB | European Hydrogen Bank |
| ENNOH | European Network of Network Operators for Hydrogen |
| ENTSOG | European Network of Transmission System Operators for Gas |
| EU | European Union |
| FRR | Frequency Restoration Reserve |
| GHG | Greenhouse Gas |
| GO | Guarantees of Origin |
| HNO | Hydrogen Network Operator |
| HPA | Hydrogen Purchase Agreement |
| HRS | Hydrogen Refuelling Stations |
| HTNO | Hydrogen Transmission Network Operator |
| IEA | International Energy Agency |
| IIT | Institute for Research in Technology |
| IoSN | Identification of System Needs |
| IPCEI | Important Projects of Common European Interest |
| ISGAN | International Smart Grid Action Network |
| LCOE | Levelized Cost of Energy |
| LMA | Long-term Market Analysis |
| LNG | Liquefied Natural Gas |
| NBP | National Balancing Points |
| NECP | National Energy and Climate Plan |
| NHS | National Hydrogen Strategy |
| OTC | Over the Counter |
| PEMEL | Proton Exchange Membrane Electrolysis |
| PNIEC | Plan Nacional Integrado de Energía y Clima |
| PPA | Power Purchase Agreements |
| RES | Renewable Energy Systems |
| RFNBO | Renewable Fuels of Non-Biological Origin |
| RR | Restoration Reserve |
| SCR | Selective Catalytic Reduction |
| SMR | Steam Methane Reforming |
| SNG | Synthetic Natural Gas |
| SOEL | Solid Oxide Electrolysis |
| TRL | Technology Readiness Level |
| TS | Transmission System |
| TSO | Transmission System Operator |
| TTF | Title Transfer Facility |

| | |
|---|---|
| TYNDP | Ten-Year-Network-Development-Plan |
| VRE | Variable Renewable Energy |

## Executive Summary

The planning and operation of the power system will be affected substantially by the development of the hydrogen sector, mainly due to the electrification of hydrogen production.

This work explores the impact of the integration of the hydrogen sector on the power sector in three dimensions:

1) power grid planning;
2) power system development; and
3) power grid operation.

In addition, it reviews any attempt at developing a hydrogen market. How do hydrogen market mechanisms influence the whole energy system? What are the effective price signals for hydrogen suppliers/consumers? Furthermore, the report reviews how certain policies and strategies affect the transition to a hydrogen economy in both demand and supply sectors, import and export. It also reviews the national (if any) regulations of the example countries: Sweden, Spain, Belgium, Norway, Italy, Germany, Switzerland.

The deployment of electrolyzers at a large scale will have a significant impact on the electric grid. Proper planning is essential to ensure that the electric grid can handle the additional load needed to feed the electrolyzers while optimizing the resources of decarbonized generation. The electric grid planning affected by the hydrogen sector is investigated by exploring the strategies for the expansion of hydrogen production capacity, the electrolyzers' impact on the grid, their localization, business models, as well as assessing the surging hydrogen valleys.

The hydrogen sector impact on power system development analyses the impact of the hydrogen sector beyond the pure grid perspective, enlarging to the development of the whole power system and on the wider energy system, under a "system of systems" integrated perspective. It focuses on the optimal and efficient use of energy resources, infrastructure, and the provision of long-term system services such as seasonal storage and strategic hydrogen reserves.

The impact of the hydrogen sector on grid operation is investigated through exploring resource- and technology-operational modes of electrolyzers. Two types of flexibility provision are discussed:

- Short-term flexibility at grid level, where electrolyzer flexibility has the potential to provide ancillary services, congestion management and voltage control.
- Long-term flexibility at system-wide level, where capacity planning challenges can be addressed by optimizing hydrogen production and storage over time horizons from weeks to seasons to cater for long-term/long-range load and RES variations, thus also exploring the possibility of utilizing hydrogen transport and storage to enhance system flexibility.

Finally, the impact of market mechanisms on the whole energy system is explored, considering the future design of hydrogen market and policy measures to ramp up the hydrogen economy, diving particularly into EU regulatory frameworks and EU experience on market mechanisms affecting electrolyzer investments.

The national hydrogen strategies and regulations for example countries are summarized in Appendix A.

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# 1. Rationale of a hydrogen ecosystem

*This section states the global view on the hydrogen economy (production, storage and use), the current developments and the future needs.*

## 1.1. Introduction

Energy system integration refers to planning and operating the energy systems "as a whole" across multiple energy carriers, infrastructures, and consumer sectors. Energy system integration creates more robust links between them to deliver low-carbon, reliable and resource-efficient energy services at the least possible cost for society. It should aim at optimizing the whole energy system rather than decarbonizing and making separate efficiency gains in each sector independently.

Flexibility, both from short-term and long-term perspectives, will get even more crucial for the secure and efficient functioning of an integrated energy system applying a "one system view". This flexibility shall also come from sector integration: linking the various energy services – electricity, heating, cooling, gas, solid and liquid fuels – with each other and the end-use sectors, such as buildings, transport or industry. The secure and reliable operation of the coupled vectors as a whole is of utmost importance and priority for the grid operators, whose role will increase, especially during their sustainable integration.

Before diving deeper in the topic, we provide clear definitions of green, renewable, low-carbon and clean hydrogen. According to reference [1], renewable or green hydrogen is generated using only renewable energy via electrolysis, ensuing zero or near-zero carbon emission. Low-carbon hydrogen is produced with considerably lower carbon emissions compared to conventional methods. Clean hydrogen is a broad term that refers to any hydrogen generated with substantially reduced emissions compared to fossil-fuel-based methods. Thus, clean hydrogen is an umbrella term, that includes both renewable and low-carbon (for example blue) hydrogen.

### 1.1.1. Decarbonization efficiency: the need for hydrogen in the energy portfolio

In line with the "energy efficiency first" principle, this can be effectively achieved, first and foremost, by applying energy efficiency measures at all stages of the value chain and secondly by electrifying applications and processes that are technically feasible and economically viable. Where electrification is not feasible ("hard-to-abate'' processes such as high-temperature industrial heating, sea/air transport and some long-haul heavy-duty road transport), $CO_2$-free molecules such as "clean" hydrogen and its derivatives and bio-based molecules can be utilized.

### 1.1.2. Expected roles of hydrogen in the energy sector

First and foremost, clean hydrogen shall decarbonize the existing hydrogen demand, which is mainly feedstocks in the refining and fertilizer sectors, as well as steel production.

Secondly, the combination of flexible operation of electrolyzers and the physical properties suitable for storage makes hydrogen a potential buffer for the energy ecosystem on short and long timeframes. Hydrogen could help smooth mismatches between weather-dependent electricity generation versus steady hydrogen consumption and the fixed final electricity consumption. This could enable integration of large amounts of variable renewable energy (VRE) and contribute to adequacy and security of supply for both electricity and hydrogen end use. In addition, electricity production from hydrogen is technically possible and could take a role as a peak electricity resource in a fully decarbonized energy system, shifting part of existing gas and oil reserves to hydrogen stores. This could be accompanied by other new technical solutions such as thermal storage, compressed air/liquid air energy storage (CAES/LAES) and mechanical/gravity storage. Therefore, this purpose should always be assessed in a comparative way from a holistic energy system point of view to the benefit of European society. Long duration storage could also consist of strategic energy system reserve (SESR), a separately remunerated service today provided by gas and oil stocks.

If it were solely about electricity, the efficiency of batteries would be superior to the use of hydrogen. Using hydrogen as a fuel for electricity production will therefore primarily serve as a supplement in cases where electricity from batteries is insufficient or unfeasible, like inter-seasonal storage when other solutions are not available. In this case, electricity could be re-generated through hydrogen turbines (mature technology) or fuel cells. This applies to electricity production for general end-use purposes. However, it can also apply to various transport applications if batteries cannot provide sufficient energy on board a vehicle for its specific application, or if it proves impossible to establish a suitable charging infrastructure for all modes of transport. Refuelling with hydrogen and on-board electricity production using a fuel cell system could then be a viable zero-emission alternative. In addition, hydrogen can also serve as a fuel in efficient combustion engines for heavy-duty trucks.

The advantage of storing energy in the form of hydrogen compared to battery storage is that hydrogen has much broader application possibilities. This includes:

- use as an emission-free fuel in applications that are difficult or impossible to electrify (particularly various high-temperature processes in industry);
- use as an emission-free reducing agent in iron and steel production;
- use as a chemical base material (raw material/feedstock) in numerous production processes in the chemical industry;
- use in combination with sustainable forms of carbon to produce synthetic fuels, so-called e-fuels, particularly for the aviation and maritime sectors; and
- capturing solar and wind energy in the form of hydrogen or hydrogen derivatives to redistribute that energy, through export and import (trade), from areas where it is abundant to areas with a limited supply but very high energy demand.

Thirdly, hydrogen can be used for long and bulk transport as a possible energy carrier considering local boundary conditions and externalities.

Fourthly, hydrogen is promoted for the energy transition phase. Maybe one of the most contentious elements is the fact that hydrogen relies on the assumption that innovations and adaptions towards full electrification and build out of electricity infrastructure will not take place in due time. On the other hand, the ramp up of the hydrogen sector is able to proceed with full speed with some reuse of existing natural gas infrastructure and therefore help to meet ambitious political climate targets; specifically, to decarbonize hard-to-abate sectors.

Such future roles for clean hydrogen, combined with the potential of short-term flexibility provision, make electrolyzers not only a significant source of new electrical load, but rather a new relevant component of the future power system, possibly equivalent to grid-scale storage plants. Cooperation needs and opportunities arise from all previous roles, encompassing all hydrogen infrastructure, including large underground storages, given the magnitude of the infrastructures and the prevalence of a weather-dependent RES-dominated electricity system. Storage also caters for differential speed of implementation of capacity, and volumes of supply and consumption between the different actors.

Decarbonized hydrogen, i.e. low-carbon hydrogen in its production process, can be obtained in several ways.

### CCUS

Adding a carbon capture, utilization and storage (CCUS) process to the traditional steam reforming process from natural gas in oil refineries and chemical industries, as well as gasification of biomass and waste, is currently missing. Despite being technically mature, it is expensive and does not reach 100% $CO_2$ reduction. For widespread application, $CO_2$ logistics (transport, storage, long-term security against leakages) need to be tackled.

*Electrolyzers*

Using $CO_2$-free electricity, separation of water into hydrogen and oxygen through the application of an electric current is a consolidated technique in the chemical industry and is becoming now popular due to increasing availability of low-cost renewable energy resources (RES) such as wind, sun, hydro, geothermal and also nuclear (in theory), if they are cost-competitive.

*Pyrolysis*

Pyrolysis and other thermal or chemical processes are not yet mature and/or economically convenient processes.

*Natural hydrogen*

Identification of possible large, low-carbon and exploitable reservoirs is ongoing.

In a future net-zero energy system, largely based on solar and wind energy, low-carbon hydrogen production via electrolysis is the most relevant option, which is also the only case impacting directly on the power system. Therefore, this report focuses only on this method of hydrogen production, and on the logistic infrastructures, which are needed for all cases.

## 1.2. Main future use cases for hydrogen

In the future, hydrogen is expected to provide longer-term flexibility to the power system. It complements major use cases for hydrogen as a fuel and feedstock, namely, industry and transport, asking for large amounts of hydrogen at lower cost. To estimate the potential of hydrogen for the power grid and anticipate its impact, it is first important to understand the key drivers of the demand in other sectors' use cases, including both power to hydrogen (P2H) and hydrogen to power ($H_2P$) applications.

### 1.2.1. Industry as primary future demand for hydrogen

Hydrogen is a versatile industrial feedstock with unique decarbonization applications driving its demand. Below are the main use cases of hydrogen envisaged in industry, particularly focusing today on steel production, refineries, and ammonia production, while in the future also ceramics, glass production and transport.

*Steel production*

Steel production would use hydrogen as a reducing agent of iron (direct reduction of iron, DRI) to convert iron ore into iron without $CO_2$ emissions. Traditionally, natural gas or coal is used for this purpose, but hydrogen offers a cleaner alternative as it produces water instead of $CO_2$ as a by-product. Hydrogen could also be used indirectly to replace natural gas in burners to produce heat in several furnaces used in the steel making process.

*Decarbonizing refineries*

Decarbonizing refineries using hydrogen has two main use cases that both remove sulphur, nitrogen, and metals:

- Hydrocracking process, where hydrogen is used to break down larger, more complex hydrocarbon molecules into lighter, more valuable products such as gasoline, diesel, and jet fuel.
- Hydrotreating uses hydrogen to remove impurities (sulphur, nitrogen, and metals) from petroleum products. It helps in producing cleaner fuels and meeting stringent environmental regulations [2].

*Ammonia production*

Hydrogen is a critical component in the production of ammonia via the Haber–Bosch process, which is primarily used to make fertilizer.

### 1.2.2. Decarbonizing transport via hydrogen and e-fuels

There are two ways of decarbonizing transport: using hydrogen directly (without conversion to other fuels) in a fuel cell or internal combustion engine for light-duty and heavy-duty vehicles for which direct electrification is not suitable; or indirectly in hard-to-decarbonize transport (e-fuels converted from hydrogen to shipping diesel or even methanol or ammonia as new shipping fuels or aviation kerosene).

### 1.2.3. Hydrogen as power system flexibility provider

Flexibility needs and sources for the power system – P2H in particular, using electrolyzers – is expected to have a much higher impact on the power system; for instance, through providing system services ranging from short-duration flexibility to long-duration flexibility and adequacy.

*Short-duration flexibility*

Short-duration flexibility, ranging from seconds to hours, can be used to balance the power system within the day and is needed to ensure power system stability [3]. Electrolyzers are expected to become a promising source of short-duration flexibility participating in ancillary service markets (FCR, aFRR, mFRR and RR) as well as supporting voltage control and congestion management [4].

*Long-duration flexibility*

Long-duration flexibility compensates for extended periods (up to several weeks) of shortage of wind, solar, and hydro generation. H2P is expected to mostly contribute to this use case in the power sector. By using excess renewable energy to power electrolyzers, the produced hydrogen could be stored or used for power (when renewable generation is low), transport, industry, etc. P2H, especially in combination with hydrogen storage, is further seen to contribute to this use case in the future.

*Adequacy*

Adequacy requires enough resource capacity available to avoid loss of load and to meet nationally determined reliability standards. Both P2H and H2P could play a role in supplying adequate power capacity in a carbon-neutral way, such as substituting natural-gas-fuelled plants by participating in national capacity mechanisms.

### 1.2.4. Role of hydrogen-based power generation

Hydrogen-based electric power generation will not be a low-cost solution as it is dependent on the price of clean hydrogen, which will be a scarce and high-cost energy carrier for still some time. Nevertheless, hydrogen solutions can be very relevant to balancing supply and demand.

The main advantage of using rotating machines (turbines and engines) for $CO_2$-free generation in the power system is to continue exploiting their intrinsic mechanical characteristics: inertia, short circuit power, regulating speed, frequency support, reactive power provision, voltage support. This would imply a correspondingly lower need of other flexibility means, which shall indeed compete on the basis of offered cost and type of performance.

Currently, clean hydrogen is one of the most prominent solutions for large (TWh capacity) electric power generation combined with inter-seasonal renewable energy storage of hydrogen. Gas engines and gas turbines can be converted from natural gas to hydrogen operation. Blending hydrogen to natural gas and conversion of such units from natural gas to hydrogen operation has been investigated and already demonstrated up to 100% hydrogen. When 100% hydrogen is being used as fuel, the thermal efficiency of gas engines and gas turbines is similar to that observed by using carbon-containing fuels. The trade-off between efficiency, cost and $NO_x$ emissions for hydrogen power with dry low emissions is whereby lowering $NO_x$ emissions by lowering combustion temperature. This can reduce the efficiency of combustion. However, using selective catalytic reduction (SCR) to allow combustion at a higher temp incurs the additional costs of using SCR to remove $NO_x$ emissions. Co-firing with hydrogen can already reduce $CO_2$ emissions in existing gas-fired power plants in the near term.

In planning system developments, it will become important to have sufficient dispatchable power generation capacity installed which can support the stability of the electric grid in prolonged periods of high demand/low RES supply situations. Such periods would deplete other flexibility means (like direct electricity storage in batteries, flywheels, CAES) and dispatchable power generation at a significant scale will therefore be required to cope with this task. In addition to (pumped) hydropower and biomass, also other low-carbon power generation technologies must be considered for this task.

Dispatchable electric power generation units (gas turbines, piston engines, fuel cells), operated on hydrogen as a fuel, can provide residual power as well as balancing power very efficiently at different power scales (capacity) adapted to the specific conditions (e.g. capacity of cables, electric demand) at their individual connection point to the electric grid. Some of these technologies can also provide much-needed grid ancillary services such as system inertia, reactive power control, voltage control and short circuit power. Dispatchable hydrogen-based power generation can serve distributed networks down to microgrid scale (MW to kW scale) as well as large urban and industrial zones (50 to 500+ MW). Due to their favourable operational characteristics (quick response times – seconds/minutes – as well as sustained power output over longer time frames – hour/days/weeks), they can nicely complement other power provision technologies (like flywheels, batteries). Placement of hydrogen-based power generation units will need to be accounted for in respective network development plans considering additional boundary conditions such as the proximity to gas networks and storage sites for the appropriate supply of hydrogen.

Technological improvements are necessary enablers. hydrogen-based gas turbines and gas engines are mature but still need dedicated effort until commercial solutions are available for 100% hydrogen-firing large-framed gas turbines. This applies to both newly built units and retrofit solutions for existing assets. Maintaining full power capacity (no down-grading because of hydrogen), highest efficiencies (same as for today's natural gas fleet) and lowest emissions are the targets to be achieved. As the equipment will be used to meet residual load requirements, a high operational flexibility will be mandatory without compromises with respect to reliability and durability of the equipment. Steep load ramps and frequent start/stop cycles will need to be covered by respective hydrogen-fired gas turbine and gas engines.

Fuel cells will need to improve their impact on resources (use of rare materials) and increase fabrication capacity to serve more and larger projects. Development is ongoing to improve the reversibility of fuel cells, allowing to switch operation from fuel cell operation (using hydrogen for electricity production) to electrolysis mode (in particular with the high-temperature technology based on solid oxide electrolysis (SOEL)/fuel cell SOFC) using electricity to produce hydrogen.

# 2. Electrolyzer technologies

*This section reviews electrolyzer technology globally; what are the processes to enhance conversion efficiency, flexibility capabilities of electrolyzers and their technical potential to participate in different markets.*

## 2.1. Existing technologies

Current existing electrolyzers technologies are Alkaline Electrolysis (AEL), Proton Exchange Membrane Electrolysis (PEMEL), Solid Oxide Electrolysis (SOEL) and Anion Exchange Membrane Electrolysis (AEMEL) [5]. The first two are commercially available. Both technologies are at the same technology readiness level (TRL9).

According to International Energy Agency (IEA) report published in 2023, AEL and PEMEL electrolyzers were, until recently, about 70% and 20% of global operational capacity respectively. Recently, several large-scale PEMEL installations took place in Europe, resulting in a more even split in electrolyzer technologies: AEL 44% and PEMEL 53% respectively.

SOEL is developing fast and will soon be commercialized. The first SOEL electrolyzer installation (2.6 MW) took place in 2023 in the Netherlands, which was followed by a 4 MW SOEL electrolyzer installation in the NASA research centre in California. Technology readiness level (TRL) for SOEL electrolyzers is 8. In contrast to the above-mentioned electrolysis technologies, AEMEL electrolyzers are also already being commercially deployed, with smaller volumes and at smaller size for now. Figure 1 depicts global electrolyzer manufacturing capacity [6]. IEA figures are more modest, for example in 2023 it is reported 25 GW/year [5].

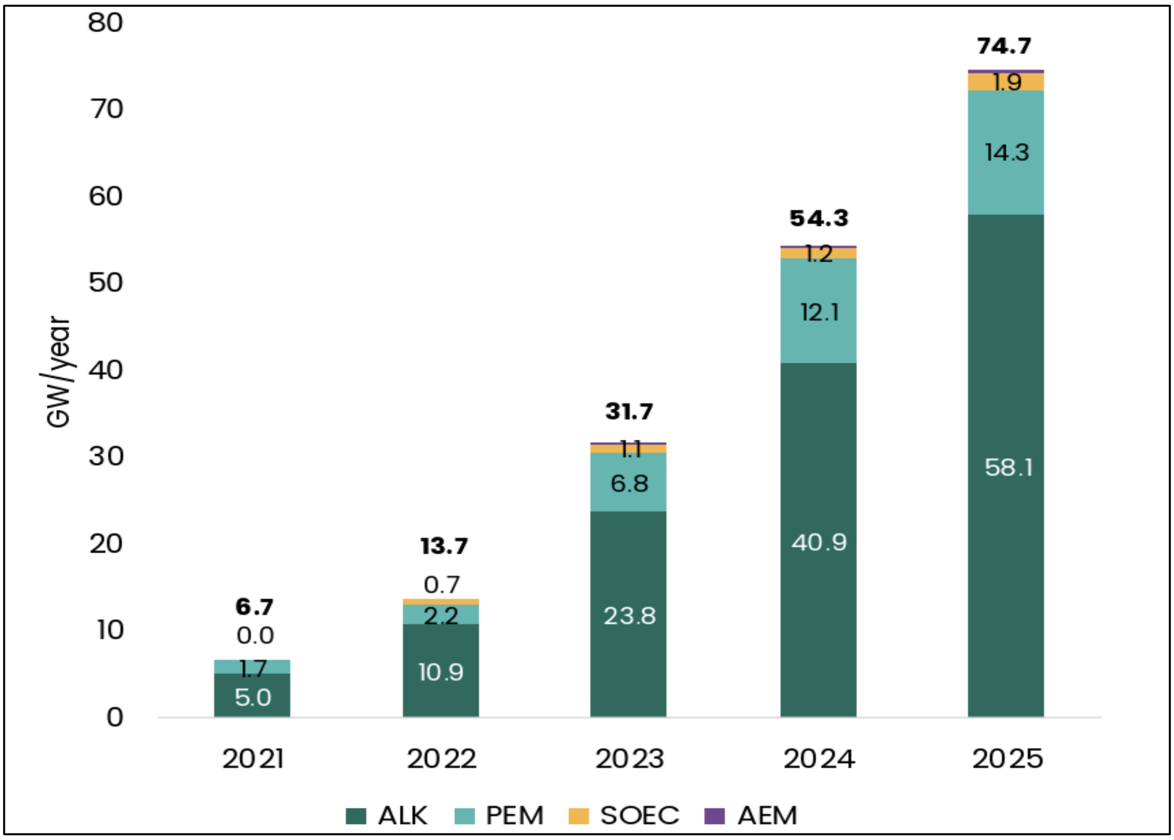


Figure 1: Global electrolyzer manufacturing capacity (source: [6]).

### 2.1.1. AEL

AEL is the most mature technology and has been widely used in industry since 1920. Alkaline electrolyzers are durable and have a reasonably low capital cost due to the relative maturity of the technology. However, low current density and operating pressure limitations negatively impact the size and cost of hydrogen production. In addition, operational flexibility is limited, and an excessively dynamic operation can cause a decrease in efficiency and gas purity. Therefore, research aimed at optimizing alkaline technology is focusing on improving both current density and operating pressure as well as designing the system to allow flexible operation, which allows for better integration with non-dispatchable renewable sources.

### 2.1.2. PEMEL

The main advantages of PEMEL technology are high power density and efficiency allowing the production of high-purity hydrogen at high pressure (>30 bar). An additional advantage of PEMEL technology is its high flexibility, which allows it to operate in standby mode with minimal power consumption, as well as the ability to operate for a short period of time (10–30 minutes) at capacities higher than the nominal load (up to 120%). By contrast, alkaline technology was initially designed to operate at constant load to meet the needs of industries, therefore, despite significant improvements in recent years, alkaline electrolyzers are still less flexible than PEMEL ones. The disadvantages of PEMEL electrolyzers include the high cost of iridium and platinum, used as catalysts, and of the fluorinated material that constitutes the membrane. Furthermore, to ensure operation at high pressure, a more complex system is required. Finally, water purity requirements, together with a shorter lifetime compared to alkaline technology, are still weak points of this technology. Current developments to improve PEMEL electrolyzers are aimed at reducing the complexity of the system to facilitate scale-up and capital costs, also by optimizing the stack design and manufacturing process to reduce the amount of expensive material to be used.

### 2.1.1. SOEL

SOELs are the most recently developed technology. It has not been widely commercialized yet, but the system has been demonstrated at laboratory scale, and several companies are involved in the deployment of this technology with demonstration projects. SOEL electrolyzers use solid ceramic materials as the electrolyte, to allow the conduction of ions, requiring significantly higher operation temperatures (>700 °C). The main advantages include high efficiency, significantly higher than the other two technologies, reduced material costs and the possibility of operating in “reversible” mode both as a fuel cell and as an electrolyzer.

## 2.2. Flexibility capabilities of electrolyzers

Depending on their technology and boundary conditions, electrolyzers could provide most grid services. References [7] and [8] state that PEMEL electrolyzers are more capable of providing flexibility compared with alkaline electrolyzers. Flexibility capabilities of different technologies are summarized in Table 1. In real use cases, according to manufacturer’s datasheet, when it is needed for them to guarantee the operation, the ranges and performances can be lower.

Table 1: Electrolyzer flexibility capability.

| | AEL [9] | PEMEL [9] | SOEL [10] |
|---|---|---|---|
| **Load range** | 15–100% of nominal load | 0–160% of nominal load | 0–100% load |
| **Hot start up** | 1–10 minutes | <10 seconds | 15 minutes |
| **Cold start up** | 1–2 hours | 5–10 minutes | hours |
| **Ramp up** | 20% per second | 100% per second | 100% per second |
| **Ramp down** | 20% per second | 100% per second | 100% per second |
| **Shut down** | 1–10 minutes | seconds | ? |

## 2.3. Electrolyzers’ technical potential to provide grid services

Figure 2 summarises the technical potential of electrolyzers to provide flexibility in ancillary service markets and Distribution System Operator (DSO) local markets [9].

| | AEL | | PEMEL | | SOEL | |
|---|---|---|---|---|---|---|
| | 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-commuted rectifiers | | | | | |
| Congestion management | Yes | Yes | Yes | Yes | No | Uncertainty about flexibility |

Figure 2: Electrolyzers' technical potential to provide flexibility in different services. Source: ENTSO-E.

Figure 2 confirms the ability of alkaline and PEMEL technologies to participate in different marketplaces and provide flexibility services. However, SOEL technology currently is not providing flexibility, and it is uncertain the potential in 2030.

### 2.4. Electrolyzer efficiencies and CAPEX: expected evolution

Electrolyzers' energy efficiency is dependent on the system design and optimization goals and it is therefore not straightforward to track their efficiencies. The overall efficiency is lower than that of the electrochemical processes itself (stack), due to energy losses in the balance of plant. If the wasted heat is recovered, the overall efficiency can be much higher. Both AEL and PEMEL electrolyzers have similar efficiencies and their flexible operation enables direct coupling with variable RES. SOEL electrolyzers have higher electrical efficiencies compared to AEL and PEMEL technologies due to high-temperature characteristics, which allows SOEL to produce more hydrogen per power unit [5], [10].

The cost of renewable electricity utilized, followed by capital expenditures (CAPEX) of the technology, are the cost components with the highest impact on the total cost of hydrogen produced, standing at 75% and 90% of hydrogen production costs, respectively, if the electrolyzer is directly connected with a RES and there is no network cost. Both cost components have a great cost reduction potential [6]. The reference [6] states that the CAPEX will be reduced by up to 70% due to the ramp-up of manufacturing capacities through economies of scale and automation. As SOEL is a relatively less mature technology, the cost reduction should be more impressive in SOEL case compared that of AEL and PEMEL technologies. As shown in Table 2, the current CAPEX values for electrolyzers are expected to be around 500 Euro/kW for AEL and PEMEL electrolysis technologies and 600 Euro/kW for SOEL technology by 2050 [6]. RES costs depend very much on location, local conditions of primary energy and technical configurations. Technology advancements can contribute to further cost reduction in hydrogen production [6].

Table 2: Electrolyzers' current values for efficiencies and costs.

| | AEL | PEMEL | SOEL |
|---|---|---|---|
| **Stack efficiency (%, LHV)** | 63–71% | 60–79% [11] | 90% and more |
| **System efficiency (%, LHV)** | 51–60% | 46–63% [12] | 76–82% [13] |
| **CAPEX (Euro/kW)** | 450–1300 | 1000–1600 | >2000[1] |
| **OPEX (%CAPEX/year)** | 2–5 | 3–5 | ? |

## 3. Hydrogen infrastructure

*This section addresses the infrastructure for transporting and storing hydrogen (either new or derived from repurposed natural gas infrastructure), which are a necessary element for building a hydrogen ecosystem as well as for creating synergies with the electricity sector.*

### 3.1. Integrating hydrogen, gas and electricity systems

The electricity system is likely to play an ever-growing role in the energy sector due to the rapid deployment of RES, thanks to technological maturity and CAPEX price reduction as well as the

[1] Considerable uncertainty due to immaturity of the technology.

clear, irreversible, trend towards increasing the share of final energy consumption met by electricity.

Among the RES, intermittent energy sources such as solar and wind are expected to assume a predominant role due to their technological and economic advantages. However, these sources are characterized by non-dispatchable and partially unpredictable production. Given the electricity system's need for continuous and precise production–consumption balancing, the significant growth of intermittent RES will drive an increased demand for flexibility and adequacy resources to ensure service quality and continuity. This need becomes even more pronounced as the expansion of non-dispatchable RES reduces the contribution of fossil-fuel-based thermoelectric generation, which has traditionally provided essential ancillary services to the electricity system.

Furthermore, the widespread adoption of renewable energy sources will, in the long-term, tend to result in frequent and prolonged periods in which production exceeds demand. For reasons of efficiency and cost-effectiveness, it is essential to avoid wasting substantial volumes of low-cost, near-zero-emission energy. Consequently, it is essential to include substantial capacity to instantaneously absorb all energy in excess (see Figure 3**Error! Reference source not found.**) by means of storage systems, as well as flexibility contributions, which can be provided by distributed generation and demand-side management. Storage can be provided either directly by electrochemical batteries or by means of other kinds of storage (e.g. pumped hydro, hydrogen) once electricity is converted into other carriers.

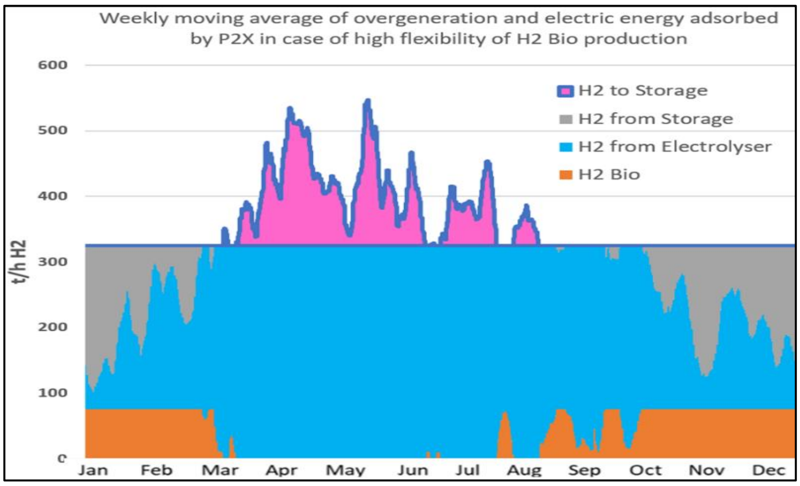


Figure 3: Simulation of a real case over generation scenario in Italy (Source: scenario analysis led with TIMES-RSE model).

In particular, hydrogen production from electric energy, constituting itself a highly flexible and modifiable electric load, enables the storage of surplus electric energy for extended periods (weeks or months) – a capability not available with electrochemical storage systems. Energy system flexibility is provided primarily by using electric energy to produce hydrogen, store it, then convert the hydrogen into electric energy at a later stage to meet demand in the power sector or by using it directly as a feedstock to meet end-user demand.

Within the framework of planning and analysing an integrated electricity, gas, and hydrogen system, the different energy carriers (electricity, gas, and, in the future, hydrogen) are increasingly interdependent. While grid planning and system development activities shall remain entrusted (or at least co-entrusted) to respective grid operators, nonetheless there is an increasing need for a joint planning of the different grids for the sake of a global minimization of the system costs, by adopting common scenarios under a multi-energy grid-planning approach. The importance of adopting such an approach is reflected in numerous policy documents. Just to mention a couple of them, at European Union (EU) level, the European Commission (EC) published already in 2020, *Powering a climate-neutral economy: An EU Strategy for Energy System Integration* [14].

In this document, we find, "Energy system integration – the coordinated planning and operation of the energy system 'as a whole', across multiple energy carriers, infrastructures, and consumption sectors – is the pathway towards an effective, affordable and deep decarbonisation of the European economy".

The more recent document *Electricity infrastructure development to support a competitive and sustainable energy system – 2024 Monitoring Report* [15] published by the EU Agency for the Cooperation of Energy Regulators (ACER) invites grid developers "to extend the use of multi-vector scenarios to grid development planning at the national level and ensure consistency between EU TYNDP and national scenarios".

The European Network of Transmission System Operators for Electricity (ENTSO-E) and the European Network of Transmission System Operators for Gas (ENTSOG) have recently started to publish joint electricity–gas scenarios to support the vision of the Ten-Year Network Development Plan (TYNDP) 2024. These scenarios are publicly available on the web [8]. While introducing such scenarios, ENTSO-E and ENTSOG declare "The scenarios evaluate the interactions between the gas, hydrogen and electricity systems, vital to delivering the best assessment of the infrastructure from an integrated system perspective".

Finally, the *Hydrogen and decarbonized gas markets package* by the EC [16], adopted in May 2024, fosters the integrated network planning between electricity, gas and hydrogen networks.

Adopting an integrated multi-carrier grid-planning approach requires, on one side, an update of the scenario-building framework and, on the other side, an important advancement in methodologies, modelling tools and simulation schemes for traditional grid planning, for adequacy resource assessment, and for resilience analysis.

In the planning stage, the complexity of a sector-integrated system is multiplied by the large uncertainty of most of its fundamental variables: RES capacity development and its intermittent generation pattern, load development between contrasting energy efficiency actions and electrification of other sectors, P2H projects (or more broadly, P2X projects), impact on natural gas system. P2H represents one of the most impacting trends, due to its size and to the correspondent impact on the natural gas system (hydrogen might substitute a quota or even all the natural gas flowing in today's pipelines and users' devices). Several techniques are possible to produce hydrogen, which can be classified by the carbon content of the hydrogen produced (see Figure 4 [17]). However, among such technological options, the "green" process, through electrolysis coupled with renewables is currently deemed as (nearly) the only one compatible with the pending European decarbonization policies.

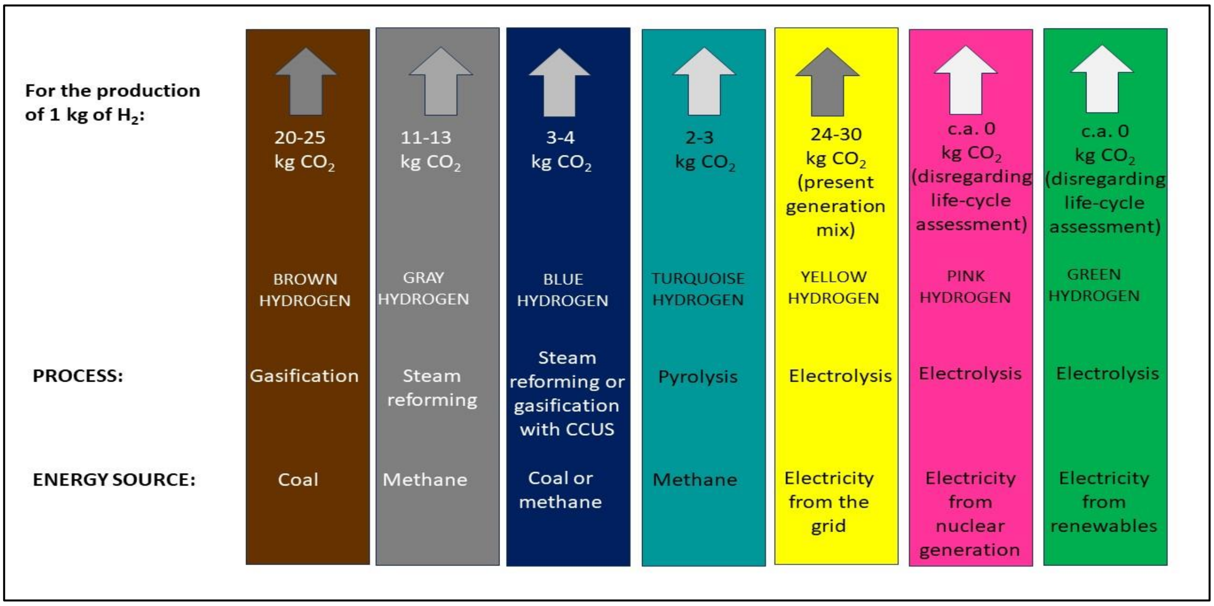

Figure 4: $CO_2$ generation for different hydrogen production technologies.

The main issues to be tackled to best integrate the upcoming set of large electrolyzers into the evolving energy system can be summarized as follows.

*Location*

Logistic configuration and operational mode of new electrolyzers are strategic questions. An appropriate coordination between hydrogen projects and electricity/gas developments is needed to ensure compatibility and optimality at energy system level.

*Electricity grids*

At European level ENTSO-E has already developed some methodologies, like multisectoral planning and dual assessment of projects – see *ENTSO-E Roadmap for a multi-sectoral planning support* [18] within its framework planning process, TYNDP. In any case, such methodologies and application mechanisms need to be further developed together with stakeholders and approved by the relevant national energy authorities.

The impact of electrolyzers on the electric grid will be relevant. Therefore, it is paramount to include electrolyzers and other components of hydrogen production in the planning process of the power system, rather than only tackling them as a connection request.

*Business case viability*

The viability of the business case, like the impact on electricity grids, is case- and country-dependent and no "one size fits all" conclusions can be applied. Each project must be analysed within its entire framework, boundary conditions and externalities, as well as potential flexibility provision.

Hydrogen not produced with electrolyzers, as well as imported hydrogen, will aim to reduce the forecasts of domestic electricity demand necessary to feed the domestic electrolyzers.

Figure 5 provides the overview of the integrated energy systems.

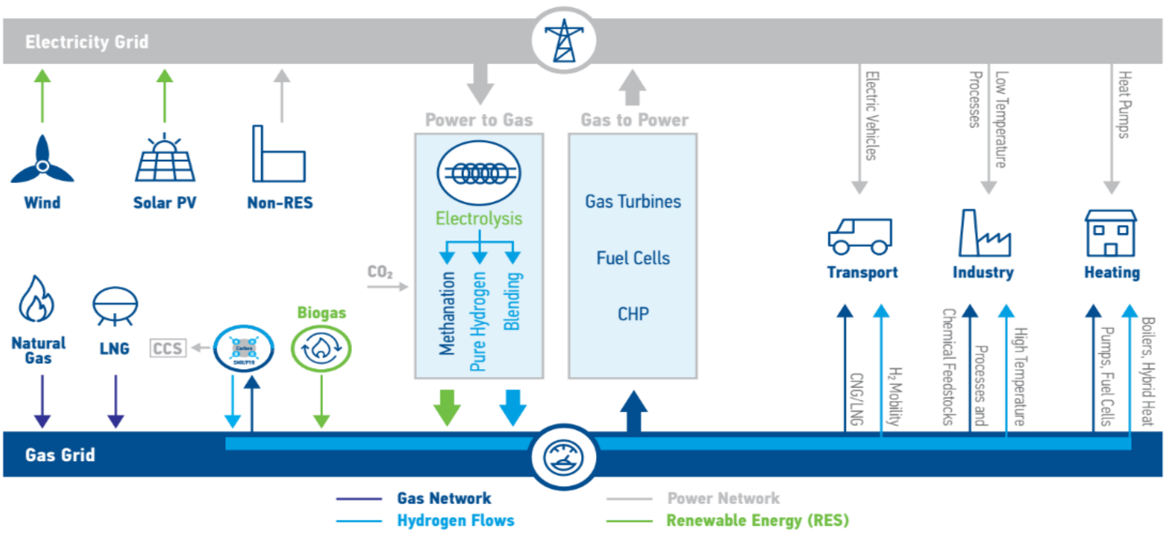


Figure 5: Overview of integrated Energy System [19].

## 3.2. Natural gas infrastructures

The natural gas infrastructures consist of different components and sub-areas and are usually understood as the connection between primary energy source production and its consumption by the consumer. In addition to natural gas grids (pipelines), this includes infrastructure facilities for transportation by road, rail and water, as well as related storage facilities for a complete supply chain.

Like the electricity system, gas grids consist structurally of transmission backbones and distribution networks, characterized by different pressure levels (high/low pressure). Different from electric grids, the gas grids are designed and operated for pre-defined mass flows; reversing the flows is possible, requiring adjustments in compressors and control devices. Transmission grids are used for long-distance transportation at higher pressure levels (> 20 bar), whereas within the distribution grids, regional and local distribution to final end-users takes place at lower pressure levels (< 20 bar). During transportation, the gas passes through many pressure levels connected via pressure regulators. The use of compressors is particularly necessary at the level of long-distance transportation to compensate for the pressure loss that occurs over long transportation distances. In terms of components, gas networks mainly consist of pipelines, pressure regulators, safety devices, compressor stations and shut-off valves, which are dimensioned for use at the corresponding pressure level.

The supply of natural gas and its transportation show quite uniform profiles over time, while consumer load profiles are usually uneven, withdrawing the gas according to their actual demand. This applies both to daily and seasonal variability; in particular, due to the high share of heating-related consumptions, a marked seasonality exists between winter and summer ("thermal year" starting in October), thus requiring large intraseasonal storage capacities. Gas supply companies use very large underground storage facilities as supplementary gas inflow sources in winter, which must be filled in the summer period, implying heavy financial charges for anticipated purchase of gas. Such gas stocks also serve as strategic reserve against supply shocks due to technical or geopolitical reasons. Notwithstanding the technical and financial costs, as well as the related energy losses, the practice of stocking gas is convenient since it avoids oversizing the capital-intensive supply pipelines and thus optimizing their utilization factor at almost constant full rate.

Short-term load balancing is also made through pipeline stack, i.e. the pressure modulation of the volume of gas present inside the pipelines, a very useful characteristic of molecular energy which is not possible with electrons in the electricity grids. Longer-term balancing and gas storage instead requires large compressing/decompressing phases, which require intense energy consumption (electric or gas-driven compressors), then released in the form of heat during withdrawal/pressure reduction. This process is associated with additional losses.

Both above-ground and underground natural gas storage facilities are used. Above-ground storage facilities are mostly used to compensate short-term modulation of gas inflows and outflows, while underground storage facilities are used to compensate for longer-term load patterns variations and seasonality.

## 3.3. Using existing gas infrastructure for hydrogen: blending and repurposing

The beginnings of the gas system go back more than a century. Over the course of time, large-scale expansion took place so that today, in Europe, there is an extensive and capillary gas infrastructure, which could become obsolete due to the intended phase-out from fossil fuels. Phase-out has started for coal in power generation and is starting for oil in the mobility sector, and natural gas will follow, with a country-specific trajectory not yet defined and depending also on world economic and geopolitical trends. From the perspective of optimal use of resources and asset bases, as well as of smooth transition to the future decarbonized energy system, it must be investigated how and how much of the natural gas infrastructure can be used (blending) or reused (repurposing) for the upcoming hydrogen supply system.

The use of existing gas grid infrastructure for the transportation of hydrogen, the blending and rededication of the existing gas grid infrastructure is currently under discussion.

Blending refers to the addition of hydrogen within the existing natural gas supply. However, blending reduces the value of hydrogen in terms of economics and efficiency. Furthermore, the blended product, considering the decarbonization target of using the hydrogen vector, can only be used to produce process heat and heating buildings (burning fuel). Indeed, if pure hydrogen is needed, it must be separated from methane with high effort and costs. As it changes the gas quality, blending must be carefully considered for quality-sensitive end-use applications and for its use of the infrastructure (gas network and storage).

Blending is possible up to a certain threshold based on the differing chemical properties. Based on [20], and shown in Figure 6, blending is generally possible, but the maximum hydrogen level is component-dependent. The table in Figure 6 presents selected examples of different $H_2$ blending rates for the transmission system (TS), storage (ST), distribution system (DS), and utilization (U). The colour coding indicates: dark green – feasible without adjustments according to current knowledge; light green – modifications may be needed; yellow – conflicting references exist and further R&D or clarification is required; orange – significant modifications or replacements are necessary; red – not technically feasible. The most important technical challenges are a higher propensity to leak due to the smaller molecule size, a higher flame temperature in the combustion process, and a greater risk of embrittlement of steel pipelines.

The transmission pipelines can be adapted to a 10% hydrogen–natural gas blend because the hydrogen transmission requires higher pressure to be supplied by compressors (due to the lower density of hydrogen than natural gas), which have the lowest hydrogen tolerance. Currently, compressors used in transmission networks allow for pumping 10% hydrogen. On the other hand, distribution networks, due to lower pressures, are characterized by a higher tolerance – it is possible to transmit 50% hydrogen. Some parts of the natural gas distribution system present a very high tolerance, with polyethylene distribution pipelines capable of transporting up to 100% hydrogen.

A recent study, *Study on the reuse of oil and gas infrastructure for hydrogen and CCS in Europe*, for key gas and oil entities in Europe, analysed approximately half of the total offshore pipeline length and approximately 30% of the onshore oil and gas pipelines. For hydrogen, it was concluded that most of the offshore pipelines and almost 70% of the onshore pipelines can be reused for full hydrogen use, considering the current state of knowledge/standards. The remaining length of the pipelines is promising for reuse but would require more testing and/or an update of standards to be reusable. None of the pipelines analysed can be categorically excluded from reuse as of today. Additionally, it was concluded that, depending on the demand/production locational assumptions, the minimum reusable offshore pipeline length for hydrogen is between 2% and 25%. With regards to onshore, based on the demand/production locational assumptions taken in this study, the minimum reusable pipeline length for hydrogen is 20% to 30%. The blending of hydrogen has been practically tested in numerous projects around the globe. [20]

| | | [%]→ | 2 | 5 | 10 | 20 | 25 | 30 | 40 | 50 | 60 | 70 | 80 | 90 | 100 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TS | Pipeline (steel, > 16 bar) | 10% | | | | | | | | | | | | | |
| TS | Compressors | 5% | | | | | | | | | | | | | |
| ST | Storage (cavern) | 100% | | | | | | | | | | | | | |
| ST | Storage (porous) | | | | | | | | | | | | | | |
| ST | Dryer | 5% | | | | | | | | | | | | | |
| TS/DS | Valves | 10% | | | | | | | | | | | | | |
| TS/DS | Process gas chromatographs | | | | | | | | | | | | | | |
| TS/DS | Volume converters | 10% | | | | | | | | | | | | | |
| TS/DS | Volume measurement | 10% | | | | | | | | | | | | | |
| DS | Pipeline (plastics, < 16 bar) | 100% | | | | | | | | | | | | | |
| DS | Pipeline (steel, < 16 bar) | 25% | | | | | | | | | | | | | |
| DS | House installation | 30% | | | | | | | | | | | | | |
| U | Gas engines | 10% | | | | | | | | | | | | | |
| U | Gas cooker | 10% | | | | | | | | | | | | | |
| U | Atmospheric gas burner | 10% | | | | | | | | | | | | | |
| U | Condensing boiler | 10% | | | | | | | | | | | | | |
| U | CNG-vehicles | 2% | | | | | | | | | | | | | |
| U | Gas turbines | 1% | | | | | | | | | | | | | |
| U | Feedstock | | | | | | | | | | | | | | |

Figure 6: Blending limits of components of natural gas system (source [20]).

Achieving the specified levels of hydrogen-gas mixing will depend on the possibility of using the mixture in end-use devices. The industries already produce, for example, turbines that generate electricity, adapted to be blended with 30% hydrogen in natural gas. The upper limit of the composition of the mixture will depend on the technical adaptability of the devices. International standardization is important, defining both common standards for the transported and stored mixtures of hydrogen and natural gas, as well as adjusting the parameters of end-use devices to the supply of mixtures. Many gas heating appliances and kitchen equipment used in Europe are certified to run on a 23% hydrogen blending, but no research has been done on the service life of appliances powered by this fuel mix [21].

With the possible gradual increase in the proportion of hydrogen, the complete conversion of the gas networks to the energy carrier hydrogen is also being discussed under the topic of rededication. The large-scale continued use of the existing distribution infrastructure is particularly challenging due to the costly production of hydrogen and the necessary technical changes on the demand side (such as the installation of hydrogen boilers). At the same time, during rededication, a great deal of organizational effort is required for the simultaneous, rapid and comprehensive conversion of supply areas. Therefore, rededication only seems realistic at higher pressure levels and larger individual customers.

## 3.4. Hydrogen transportation and distribution

In principle, the origin/production site of energy (renewable electricity and fossil energy sources) are different from the location where the energy is needed. Thus, energy must be transported either in its naturally available form (e.g. natural gas) or converted into electricity or hydrogen. Nowadays, hydrogen is produced at those industrial sites where high quantities are used, and fossil energy (mostly methane) is transported to those locations. In the future, this will probably change, and hydrogen will need to be transported.

For hydrogen applications to be competitive, a cost-efficient transmission and distribution framework is required. Consequently, the transportation and distribution of hydrogen follow the same economic principles as natural gas.

In the long-term, a network of pipelines offers the most cost-efficient means of distribution, while in the short- to medium-term, the most competitive solution is to co-locate hydrogen production on- or near-site, connecting resource-rich (production via hydrolysis or other means) regions to demand centre hubs via trucks, trains, refuelling stations, and smaller industrial users (Figure 7).

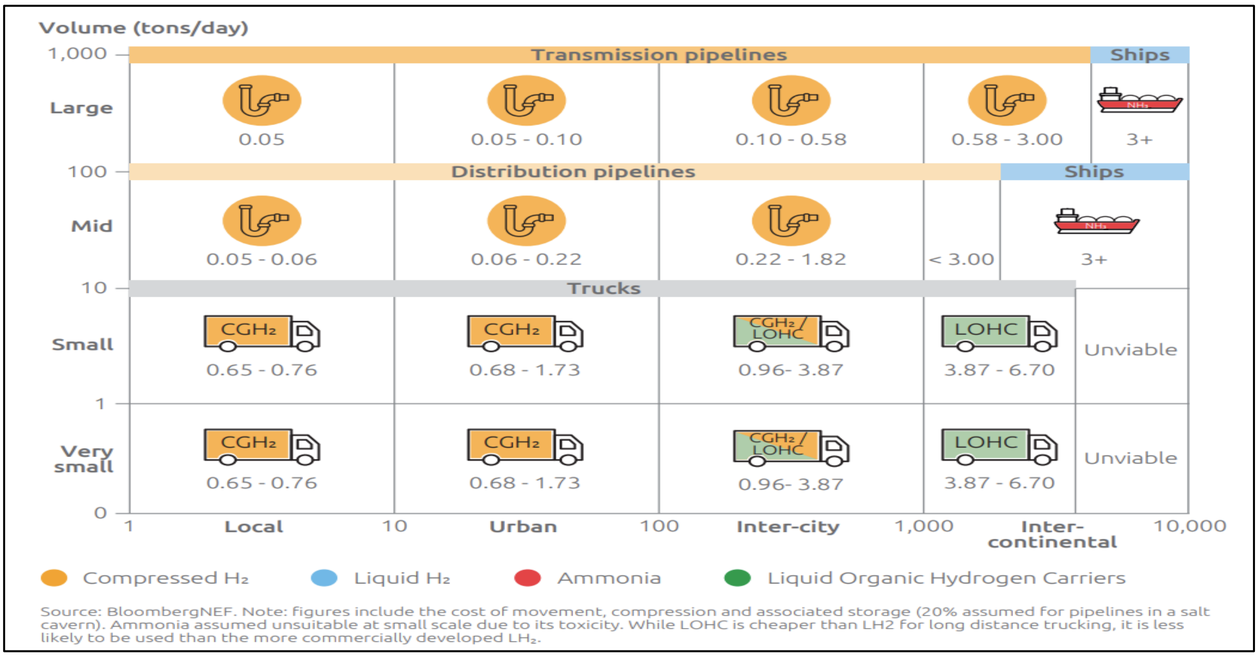

Figure 7: Hydrogen transport costs based on distance (x-axis) and volume (y-axis), $/kg, 2019 [22].

As shown in Figure 7, the most economical transportation method depends on the distance and quantities to be transported. For short distances (< 1000 km) and rather small quantities (< 10 tonnes/day), hydrogen is usually being compressed (or liquefied) and transported in tankers via road/rail.[2] On the transmission side, longer distances can be covered by shipping, where hydrogen needs to be liquefied or converted to increase its density. While several potential hydrogen carrier approaches exist, three carbon-neutral carriers – liquid hydrogen ($LH_2$), liquid-organic compounds (LOHC) and ammonia ($NH_3$) – are gaining most traction. The end use of hydrogen needs to be considered to determine the most cost-optimal solution. The transport costs highly depend on the distance and quantity of hydrogen to be transported and currently range between ~0.5 and 6 $//kg for the above-mentioned alternatives.

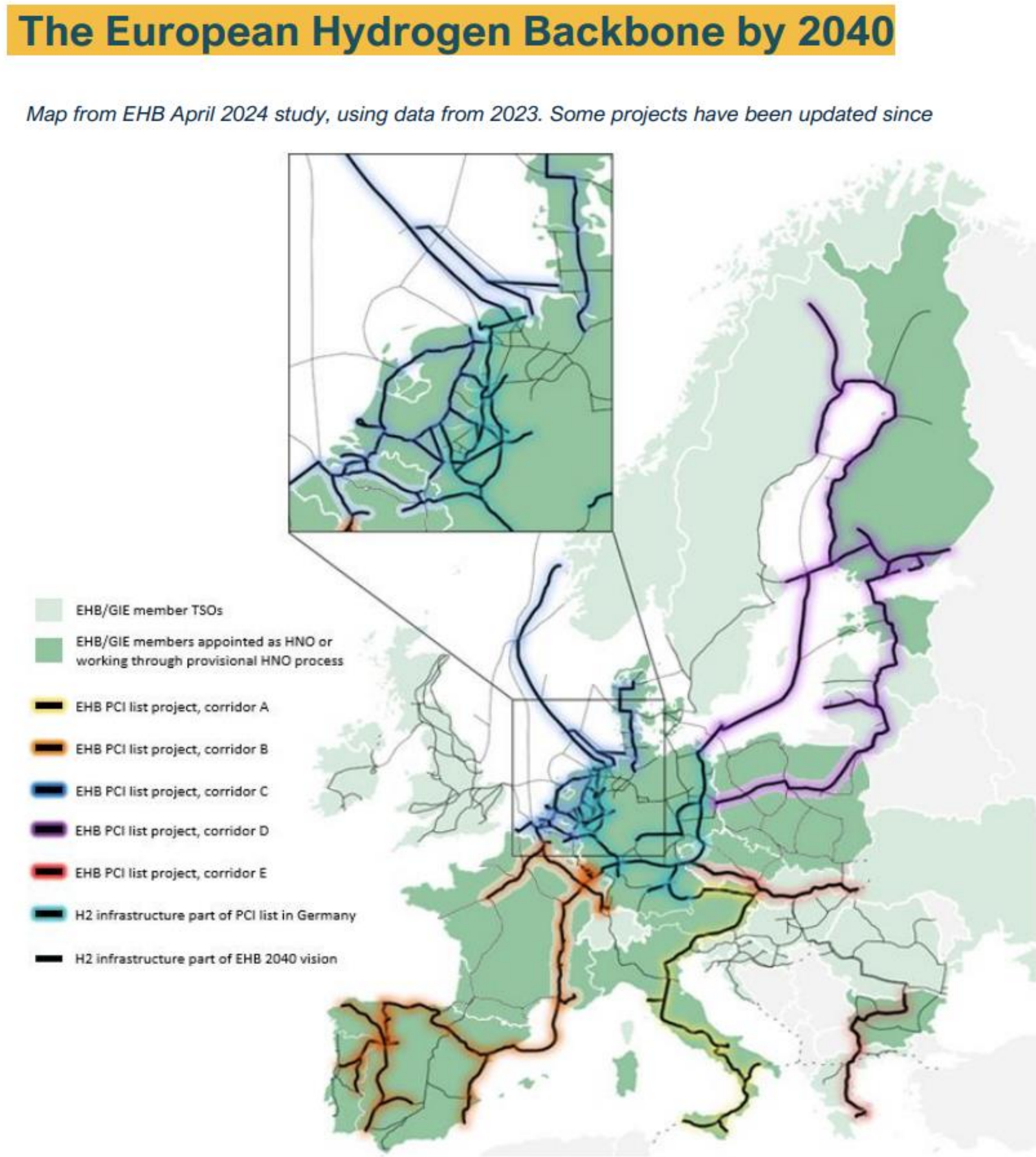


Figure 8: European gas pipelines repurposing [23].

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[2] Next to compression, innovative solutions such as the absorption of hydrogen into a liquid composition (LOHC) are being tested/researched.

Another way to transport hydrogen is via pipelines. As of today, a few dedicated hydrogen networks exist in Europe in sparse areas, especially to connect industrial sites in the same industrial area. With the upscale of clean hydrogen production, as foreseen in the EC's *Hydrogen Strategy*, the installation of a so-called "European Hydrogen Backbone" is currently planned, with a ratio of about 70% retrofitted and 30% new. Therefore, high investments of €43 to €81 billion in the retrofitting of natural gas pipelines and new hydrogen pipelines are foreseen to attain a hydrogen network of around 40 thousand kilometres until 2040 [24] where the European hydrogen infrastructure vision covering 21 countries is presented. Such a dedicated gas network would allow for cost-efficient transport of hydrogen across Europe.

Table 3: Estimated investment and operating cost based on *European Hydrogen Backbone* (2040) [25].

| | | Low | Medium | High |
|---|---|---|---|---|
| Pipeline cost | € billion | 33 | 41 | 51 |
| Compression cost | € billion | 10 | 15 | 30 |
| **Total investment cost** | **€ billion** | **43** | **56** | **81** |
| OPEX (excluding electricity) | € billion/year | 0.8 | 1.1 | 1.8 |
| Electricity costs | € billion/year | 0.9 | 1.1 | 2.0 |
| **Total OPEX** | **€ billion/year** | **1.7** | **2.2** | **3.8** |

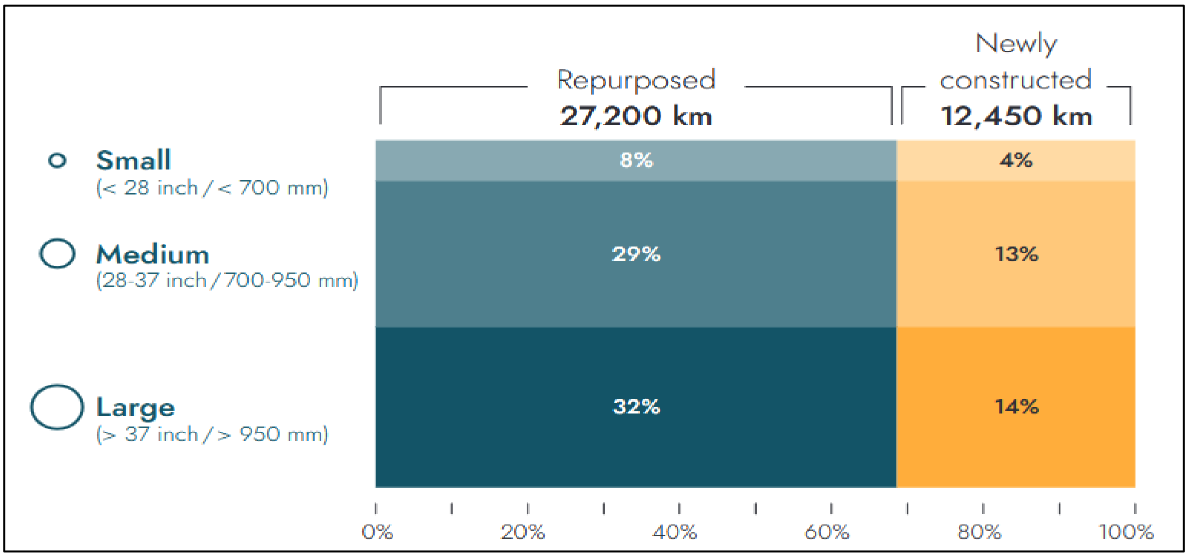


Figure 9: Breakdown based on European hydrogen infrastructure vision covering 21 countries [24], network by pipeline length, diameter, and share of repurposed vs new pipeline [24].

From a power system perspective, such a hydrogen network would be helpful to provide long-term flexibility to the energy system.

In Europe, the recent *Hydrogen and Gas markets decarbonizations packages* from December 2021 addresses this topic:

> *"A dedicated hydrogen infrastructure and market: Barriers exist for the development of a cost-effective, cross-border hydrogen infrastructure and competitive hydrogen market, a prerequisite for the uptake of hydrogen production and consumption.*

*The proposed revision creates a level playing field based on EU-wide rules for hydrogen market and infrastructure and removes barriers that hamper their development. It also creates the right conditions for natural gas infrastructure to be reused for hydrogen. This brings cost savings and helps decarbonisation at the same time.*

*The proposal introduces a European Network of Network Operators for Hydrogen to ensure sound management of the EU hydrogen network and facilitate the trade and supply of hydrogen across EU borders.*"

Furthermore, the package advocates for the establishment of the European Network of Network Operators for Hydrogen (ENNOH), promoting the creation of a dedicated hydrogen infrastructure, cross-border coordination and interconnection, and elaboration of specific technical rules.

Hydrogen transportation methods depend on the business model adopted by the hydrogen producer, its geographic location in relation to the location of markets, and access to transport infrastructure (gas pipelines, railways, ships and road transport), as well as the market demand for the hydrogen produced.

## 3.5. Hydrogen storage

Hydrogen can be produced from the surplus of energy from renewable sources and can be stored in large quantities for long periods of time. However, hydrogen has a very low density compared to other common fuels and this implies that for storage and transport purposes it must be compressed, liquefied or converted into other substances.

Due to its physical and chemical properties, the costs associated with its storage and transport are higher than those of other traditional energy sources. The possible storage options for hydrogen are still being studied today.

Currently there are different ways of storing hydrogen. Alongside the more classic and widespread systems such as compressed gas and liquified gas, there are new techniques still under study such as chemical absorption/transformation (metal hydrides, ammonia, hydrocarbons) or physisorption.

In general, hydrogen storage methods can be divided into three categories: physical/compression methods, methods based on materials, and chemicals.

### 3.5.1. Physical/compression storage

Physical hydrogen storage methods include the following main options.

*Compressed hydrogen*

Compressed hydrogen ($CGH_2$) can be stored at pressures from 50 bar up to 1,000 bar.

*Liquified hydrogen*

Liquified hydrogen ($LH_2$) can be stored at temperatures of -253 °C. Liquefied hydrogen has a higher density energy than at gaseous state but requires complex plant and additional costs due to significant energy consumption, of the order of 30% of the energy of hydrogen, based on the lower heating value.

*Cryo-compressed hydrogen*

Cryo-compressed hydrogen ($CcH_2$) has the advantage of higher energy density compared to compressed hydrogen but cooling processes require an additional important supply of energy.

*Slush hydrogen*

Liquid/solid mixture of hydrogen (slush hydrogen – $SH_2$) is a mixture of solid and liquid hydrogen at the triple point temperature. The storage density of this material is 16% higher than liquid hydrogen.

These hydrogen storage methods (compressed hydrogen, liquified hydrogen, cryo-compressed hydrogen) are currently the most mature and most used techniques in the sector.

Higher storage densities naturally pose additional challenges: the higher the storage density, the greater the amount of energy required for cooling and/or compression and the more complex the design of storage systems and related infrastructures.

### 3.5.2. Solid-state hydrogen storage

Solid-state hydrogen storage methods include the following main options.

*Metal or chemical hydrides*

Molecular hydrogen is first absorbed on the metal surface and then incorporated in elemental form (H) into the metal lattice with heat emission. It can then be released from the metal lattice by providing heat.

*Liquid organic hydrogen carriers*

Liquid organic hydrogen carriers (LOHCs) are chemical compounds with high hydrogen absorption capacity, like the carbazole derivative N-ethylcarbazole as well as toluene.

*Surface storage systems*

Surface storage systems (sorbents) enable hydrogen to be stored by adsorption on materials with specific high surface areas such as carbon nanotubes or metal organic framework.

### 3.5.3. Chemical storage

Chemical storage methods include converting hydrogen into decarbonized final products, such as SNG (synthetic natural gas) and ammonia ($NH_3$), and are effective ways to utilize the intrinsic storage capacities of the respective logistic infrastructures.

Methods based on the use of materials are being tested and developed. However, the storage densities reached are not yet adequate, the costs and/or the necessary recharge/discharge times are too high.

The geological storage of hydrogen appears to be a fundamental option in ensuring flexibility to the energy system and is a key asset in creating a liquid market for hydrogen, offering the possibility of storing large quantities in the long-term, at reasonable costs, using at least part of the existing infrastructures. Different types of reservoirs can be used such as depleted oil and gas reservoirs, aquifers and salt caverns.

To date, operational experience for the storage of hydrogen in caverns exists only in some areas of the USA (two in Texas) and Europe (UK at Teesside, France at Etriez). However, from the perspective of large-scale, long-term, and flexible energy system deployment, the most promising solution is the underground storage in depleted natural gas reservoirs or saline aquifers, even if this solution is still little implemented due to the dynamics that could be generated following the storage of hydrogen in a porous rock containing other fluids.

Salt caverns are considered a valid option due to the high holding capacity and generally inert nature of rock salt; however, the presence of impurities or sulphate layers may affect hydrogen purity or cavern integrity [26]. Storage in saline cavities also allows flexible operations with fast injection and dispensing cycles.

Nonetheless, the feasibility and sustainability of the storage process have yet to be demonstrated. Studies are therefore needed to provide concrete tools to support the development of hydrogen accumulation in the subsoil.

The storage of the hydrogen–natural gas mixture ($H_2NG$) in depleted reservoirs or saline aquifers is still under study. This is an important and advantageous option as it would allow for large capacities and the use of existing infrastructures and networks for methane. However, the percentages of hydrogen in natural gas would be rather low to obviate both problems of the energy yield of the mixture and the compatibility with the infrastructures of the existing gas network. An alternative that would make it possible to use existing infrastructures while also avoiding the criticalities linked to the behaviour of hydrogen could be to use hydrogen for methanogenesis i.e. the production of methane from clean hydrogen and carbon dioxide and its accumulation in depleted fields.

It must be remembered that, compared to methane, hydrogen is a much smaller and lighter molecule which, under certain pressure and temperature conditions, can easily interact with bacteria, minerals or materials (e.g. steels), precisely in porous formations, causing various problems of sealing or corrosion of the structures. For these reasons, feasibility and impact studies regarding the geological storage of hydrogen are more necessary than ever, aimed not only at assessing the capacity of the reservoir but also at verifying their tightness.

Hydrogen transport infrastructures include intrinsic storage capabilities, in terms of ship loading, pipeline gas-stack, and loading/unloading stations. This can be relevant for short-term and small-volume operational flexibility.

A very relevant feature of hydrogen production is the possibility to store large amounts of energy for an indefinite term (unlike thermal energy storage), in form of molecules (hydrogen or any of its derivatives). Despite the financial cost of keeping a valuable asset as working capital, this kind of storage is required for two reasons:

- System reserve, complementing other forms of security of supply, like combined cycle gas turbine (CCGT) in standby.
- Seasonal storage, where seasonal consumption patterns are present, as it is currently for natural gas consumption (winter-summer). This can now be extended to some generation patterns such as seasonal winds and annual sunshine cycle.

Large storage volumes are found in underground caverns or depleted gas reservoirs, but they are not widespread and not equally geographically distributed, so a dedicated study should be carried out to identify locations, volumes, technical constraints, and costs of this alternative.

The choice of the method and form of hydrogen storage depends on its future end use, i.e. whether it will be transported and over what distances, and in what quantities, or whether it will be used at the storage site, for example when providing system services for the electricity grid operators, or in industrial processes.

The use of hydrogen for energy storage will depend primarily on the costs of hydrogen production, but also on the costs of its storage and the model of the power system operation. Hydrogen production costs will be lower if it is produced from surplus energy from renewable energy sources in the low load bands of the system.

Figure 10 presents hydrogen storage options.

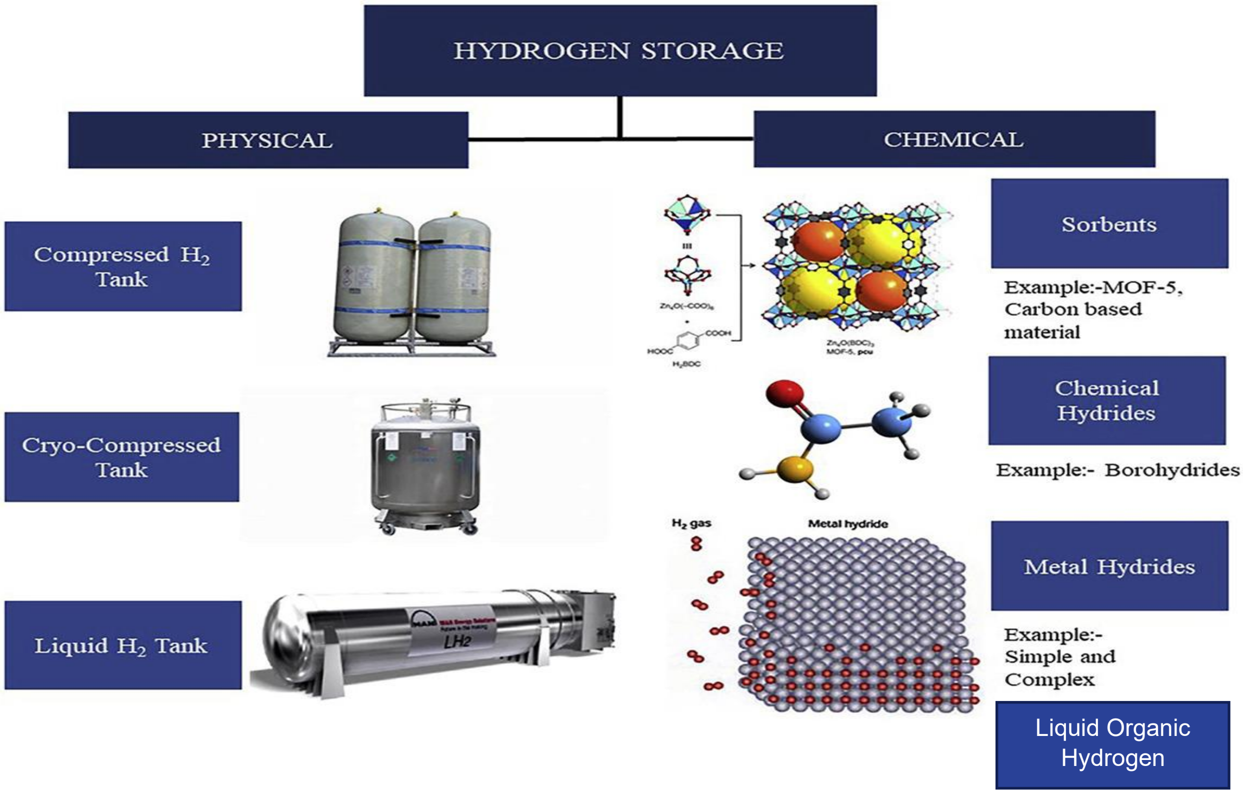


Figure 10: Hydrogen storage options [27].

Characteristics of underground salt cavern storage and tank storage are summarized in Figure 11.

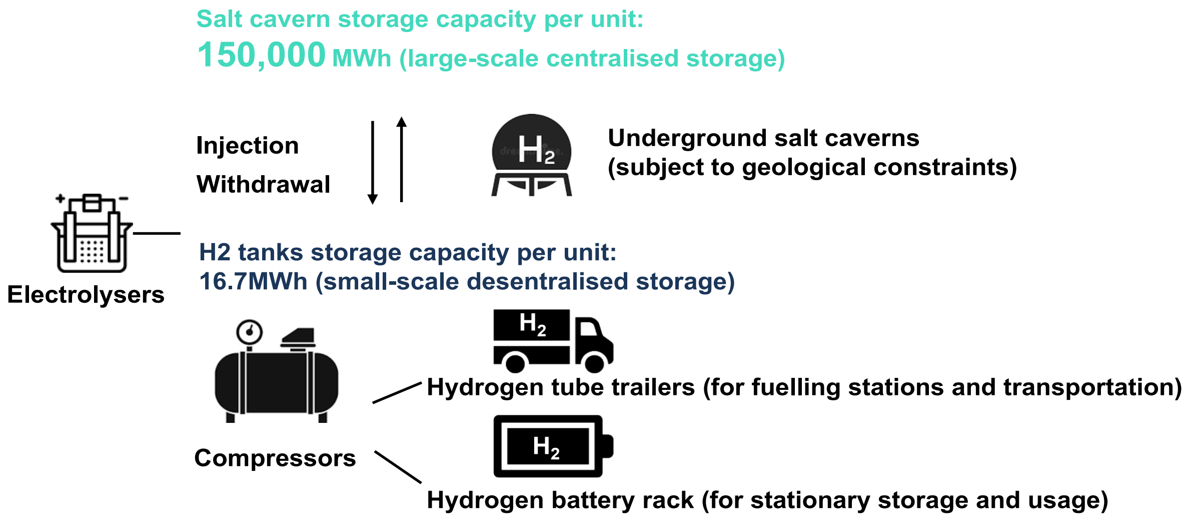


Figure 11: Key characteristics of two example hydrogen storage options (underground salt cavern storage and tank storage).

# 4. Hydrogen sector impact on power sector, transmission and distribution grids

## 4.1. Hydrogen sector impact on electric grid planning

*This section reviews strategies for the expansion of hydrogen production capacity and, consequently, the relevant transport infrastructures and their impact on the electric grid planning.*

### 4.1.1. General considerations and impact on grid expansion

Increasing the penetration of RES in the electric system requires necessary energy storage solutions like batteries, pumped hydro or hydrogen storage. In the last category, clean hydrogen production by means of electrolyzers is generally considered as the solution which best complies with the current decarbonization needs. Electrolyzers can contribute to smooth peak electricity demand, especially when scaled up for a large hydrogen production.

A deployment of electrolyzers at a large scale will have a significant impact on the electric grid. Proper planning is essential to ensure that the electric grid can handle the additional load needed to feed the electrolyzers while minimizing any waste of RES generation. From the other perspective, it can be reasonable to consider placing the electrolyzers where the electric grid is already fit for feeding them (or can be made fit by means of a relatively small investment). In this way, the integration of electrolysis with demand-side management tools can help balance loads and reduce stress on the grid.

Electrolysis, depending on the size of the installation, can offer significant flexibility benefits to the electricity system, both on the demand and supply sides, compared to other hydrogen production technologies such as hydrogen produced from steam reforming and CCS, or pyrolysis. Electrolyzers can adjust their operation based on the availability of renewable energy, effectively acting as a load that helps stabilize the grid. Implementing smart grid technologies can enhance grid flexibility, allowing for real-time monitoring and management of energy flows. On the other hand, smaller electrolyzers connected to RES generation fields can be also connected to the electric grid, so that they rely on grid power when renewable energy is not available. This flexibility can help balance supply and demand and reduce the need for additional storage capacity.

The extra electric energy consumption due to electrolyzers is influenced by the type of electrolyzer technology, the cost and availability of renewable electric energy, and the operational flexibility of the electrolyzer. Efficient management of these factors is crucial for optimizing the overall energy consumption and cost-effectiveness of hydrogen production.

In terms of electric grid response, PEMEL electrolyzers are known for their fast response times, making them suitable for integration with renewable energy sources. However, they tend to have higher capital costs compared to other types. AELs are more mature and have lower capital costs but are slower to respond to changes in power supply as shown in Table 1. The SOELs operate at high temperatures and can achieve very high efficiencies, but they are still in the early stages of commercial development and have high capital costs. This technology is less independent from the electric grid because it needs a source of heat such as recovery heat from industrial processes.

The future trends show new emerging technologies, such as advanced electrolyzer designs and hybrid systems, that combine electrolysis with other processes; for example, the hybrid system of hydrogen generation by water electrolysis and methane partial oxidation. The landscape of hydrogen production will evolve.

The availability of renewable electric energy can vary depending on geographic location and the time of year. Electrolyzers need to be able to operate flexibly, to take advantage of periods when renewable electric energy is abundant and cheap. Flexible operation can also reduce the need for expensive grid upgrades and additional storage capacity. To facilitate the integration of electrolyzers into the energy grid, standardized testing protocols and regulatory frameworks are essential. Projects like the EU's *QualyGridS* aim to establish these protocols to ensure mutual understanding between the electricity and hydrogen industries. These protocols guide the design and selection of grid-service-oriented electrolyzer applications and support the transition towards a fossil-free energy future.

In terms of costs, since electric energy consumption constitutes the largest share of clean hydrogen production costs by electrolysis, stable electric energy prices directly translate into stable hydrogen costs. Even if, in short-term scenarios, hydrogen production cost trends appear rather high, clean hydrogen should prove a competitive market option due to long-term cost trends.

All national hydrogen strategies, together with IEA, Hydrogen Council and other authoritative institutes, converge towards a 2050 scenario in which the combination of low energy costs and CAPEX reductions leads to an estimate of the cost of hydrogen production of around 2–2.3 €/kg, corresponding to 40–50 €/MWh. This case takes advantage of “excess” electricity available at a very low marginal cost during peak RES hours, which will certainly be a realistic scenario at the 2050 time horizon. The downside is that, by operating only during a limited number of hours per year (e.g. 2,000–3,000 hours out of 8,760 total), the electrolyzers have a low utilization factor. Therefore, the initial investment for the purchase of the plant (the CAPEX) must be “amortized” (i.e. repaid) on a smaller number of kg of hydrogen produced. This case is characterized by low energy cost but a high capital cost component.

Another option is the production of hydrogen with energy generated by dedicated RES plants. In this case the cost of energy must be assumed equal to the levelized cost of production of energy (LCOE) from solar or wind, which is higher than in the previous case. The number of annual hours of production is also higher, even if only marginally. The result in terms of hydrogen production cost is 3–3.5 €/kg, corresponding to € 60–70 €/MWh. In this case, the cost of energy is not tied to the market price, but to the LCOE of the renewable plant. The LCOE represents the average “all-in” cost to produce one MWh of energy over the entire life of the plant (construction costs, O&M, financing, etc.). The huge advantage is that the system (e.g. solar park + electrolyzer) can be designed to maximize the operating hours. A higher utilization factor (e.g. 4000–5000 hours or more, perhaps with the help of batteries) means that the initial investment (CAPEX) is distributed over a much larger amount of hydrogen produced. The incidence of the cost of capital per kg of hydrogen production, therefore, decreases. This case is characterized by a (comparatively) higher energy cost, but a lower incidence of capital costs per kg of produced hydrogen.

The last case analysed corresponds to production with electric energy acquired from the market with a renewable guarantee of origin or with long-term contracts (power purchase agreements, PPAs). This electric energy consumption would affect dispatch costs on the electricity grid (as in the first case) and would not actively contribute to the reduction of overgeneration (as in the case of production from dedicated RES). Similarly to the second case, participation in ancillary services would be possible. These services include frequency control, voltage control, congestion management, and black start capabilities. Electrolyzers can quickly respond to grid load variations by consuming excess electric energy during periods of low demand and generating electric energy during peak demand when integrated with fuel cells. This dual functionality helps in maintaining grid stability and reliability. The main advantage of this last choice is to be found in the logistics downstream of hydrogen generation, where a more regular hydrogen production throughout the year would limit the need to resort to seasonal storage.

### 4.1.2. Pros and cons of hydrogen storage for providing services to the electric grid and reducing the need for grid expansion

Grid congestion occurs when the capacity of a transmission line is saturated, even just for some hours during the year, and this prevents the cheapest generators from being dispatched instead of more expensive ones. This phenomenon can be caused by high demand during peak times or by positive generation spikes of intermittent RES. Employing storage systems as well as exploiting system flexibility can make grid congestion less frequent or less severe. This is the preferred solution whenever the cost of the grid refurbishing action needed for eliminating (or reducing) congestion outweighs the advantages that could be achieved by eliminating the congestion itself (lower market prices and a more optimal system dispatch). This can be the case, e.g., for positive spikes of RES generation that occur not so frequently during the year.

Hydrogen has a high energy density by weight, making it an attractive option for energy storage. It can be produced from surplus renewable energy during peak generation periods. This allows for the storage of excess energy that would otherwise be lost. It can store more energy in a smaller and lighter package compared to batteries. It can be stored for long periods without significant losses, so it can play a pivotal role in seasonal and diurnal energy storage, offering a buffer for renewables and helping to balance supply and demand by storing excess energy for later use. Hydrogen can play an important role also for short-term storage, serving as a buffer against daily RES and load fluctuations. For instance, during high-demand periods, hydrogen can be converted back to electricity using fuel cells or gas turbines. This flexibility helps in adjusting to rapid changes in energy demand, providing grid operators with a reliable resource for balancing supply and demand. Fast response times make operational storage suitable for stabilizing the grid during peak demand or sudden drops in renewable generation. It also reduces the need for “peaker” plants, which often rely on fossil fuels. On the other hand, production, storage, and transportation of hydrogen can be expensive due to the need for specialized equipment and infrastructure.

The process of converting electricity into hydrogen and back to electricity involves energy losses, reducing overall efficiency. Furthermore, hydrogen is highly flammable and requires careful handling and storage to prevent accidents. The choice between seasonal and short-term storage, as well as operational storage versus long-term seasonal storage, depends on the specific needs and circumstances of the energy system. Proper planning and integration are essential to maximize the benefits and minimize the drawbacks of hydrogen storage.

### 4.1.3. Impact of electrolyzers on grid planning

Future grid planners will have to lead system studies to locate the most likely positioning of electrolyzers to design the interventions to be brought in the electricity grid. However, as it is still now the case for small RES generation, private investment in electrolyzers cannot be easily forecasted in detail. This generates further uncertainty in elaborating future grid expansion plans. Additionally, the time for leading refurbishment interventions (especially on electric transmission grids, less in distribution) can be of several years and this time is made longer and longer in the last years by public opinion opposition to grid expansion interventions. By contrast, deploying a new electrolyzer is a much easier and fast action and does not require provision of detailed information to the grid operators. This might generate delays in the capacity of the planners to follow investment actions, with the effect that congestion is at least temporarily experienced in some parts of the electric grid.

Additionally, electrolyzers consume electricity and produce hydrogen, which in turn is sent elsewhere where it is consumed. Presently, cylinder trucks are used for the transport. However, when more significant quantities of hydrogen will be requested, this will economically justify building a dedicated infrastructure (network) for hydrogen transport. At that stage, electric grid and hydrogen transport networks, with strong interactions, should be planned together in an optics of global system costs minimization.

The most relevant impacts that an increased level of hydrogen demand and generation will have on the electricity grid are in terms of: additional load in the system; location of that additional load; new load profiles modifying the flows of energy in the grid (connection points); additional source of services to the electricity system; and potential additional RES generation for the production of (clean) hydrogen.

Grid-connected electrolyzers imply the following challenges:

- Possible connection issues. The choice of the location and capacity should be considered alongside analysis of the necessary grid reinforcements.
- Need for coordinated grid planning within hydrogen valleys.
- Need to account for the additional electric load to be managed (for the quota of power not generated on-site) and the need to study use cases to determine the consumption profile.

- Need to analyse dynamic characteristics and the interactions with the wider electric system by means of stability simulations.
- Need to check control and protection schemes.
- Need to analyse the capability to provide ancillary services such as frequency and voltage support, demand response, flexibility provision for use by the grid operator according to their efficiency and cost-effectiveness compared to other flexibility means/services.

### 4.1.4. Localization of electrolyzers

The location of electrolyzers can be:

- next to generation site;
- next to consumption site; or
- in any generic point of the meshed power grid.

The hydrogen can be:

- consumed on its production site;
- transported to final consumer/storage via a specific infrastructure; or
- injected in a pipeline system gas grid (blending into the gas network).

The hydrogen's destination has also a commercial dimension, being either:

- sold to a final user;
- sold to a trader; or
- sold on a commodity market.

Use cases should be studied to assess the configuration of the electric energy source, the location of the electrolyzers and the hydrogen destination. Except the on-site use of hydrogen (the case in which hydrogen is produced and consumed in the same place), this depends substantially on the transport options and on the conditions of the infrastructure: either existing gas pipelines to be repurposed, or new hydrogen ducts to be built from scratch. Table 4 summarizes the viable options for transferring bulk amounts of energy between different regions, comparing the use of power lines with the use of hydrogen as energy carrier.

Table 4: Options for bulk energy transfer, comparison electrons with molecules.

| | **Overland** | **Sea** |
|---|---|---|
| **Short distance** | Dedicated infrastructure from hydrogen valleys (truck/tube trailer or pipeline) | Hydrogen pipeline or electric cable |
| **Mid-long distance (country/region)** | Hydrogen pipeline or overhead electric line | Hydrogen pipeline or electric cable |
| **Very long distance (inter-continents)** | Hydrogen pipelines | Hydrogen ships |

### 4.1.5. On-site production and use

Until today, hydrogen has long been a feedstock of oil refinery and petrochemical processes, with production on the same site mainly through steam methane reforming (SMR) with high $CO_2$ emissions and no need for logistics. There is little trading or transport of hydrogen, therefore it is not a market commodity, and regulation deals only with safety.

The same applies to most large industrial hydrogen uses, which are unlikely to have the possibility to build on the same site as large RES plant with a dedicated electrolyzer suitable in size and modulation to match the hydrogen offtake needs. The opposite might be feasible, i.e. to build a new hydrogen-intensive industrial plant plus its electrolyzer next to a large (existing or new) RES facility, but these are only limited cases.

For smaller-scale industrial hydrogen uses, that are expected to grow in the future, the possibility of on-site hydrogen production through electrolysis can be the most adequate solution. In fact, the production, being adjusted to demand, can be provided through smaller electrolyzers, in the order of a few MW up to a few tens of MW capacity. Examples of this are individual plants partly replacing natural gas, or hydrogen refuelling stations for private fleets.

Currently, large industrial companies looking into decarbonization are taking the approach of, first, transitioning a fraction of their operations and only then starting to gradually scale up. At an intermediate scale, on-site production (medium-small hydrogen amounts produced by a locally centralized electrolyzer that distributes hydrogen to industrial consumers located in the hub) is still possible, whereas hydrogen might have to be brought in from elsewhere in the future once demand grows. On-site hydrogen production can be enabled through the smart use of available space, such as using roof areas for deploying photovoltaic panels in an area where there would be no available space on the ground.

Apart from the renewable energy technologies most employed in such projects (wind and solar), there are other systems that enable the production of large quantities of hydrogen in relatively small areas – production of hydrogen from biomass.

### 4.1.6. Off-grid electrolyzers

Large and remote RES plants can convert their generation into hydrogen and transport it (via ships if liquid or pipelines if gas) to consumption areas, as an alternative to build new power lines, thus avoiding impacting on electric grids; in Europe, the most relevant case is with offshore wind farms, elsewhere it can be very large solar photovoltaic (PV) farm in the desert, or hybrid large PV/Wind like in Australia.

The viability of off-grid electrolyzers depends on the economic comparison, but also on the destination of the hydrogen.

- The best business case is when hydrogen can reach directly the final hydrogen users.
- An intermediate business case is when hydrogen reaches an entry point of a hydrogen grid/storage system.
- The worst business case is if hydrogen is reconverted to electricity upon reaching a meshed electricity grid.

The last case has double impact on the electricity grid, first as Power to Gas (P2G), then as G2P through gas turbines or fuel cells, but they will probably be a minority of cases, because reconversion means a loss of energetic efficiency.

### 4.1.7. Domestic consumption versus export-oriented electrolyzers

From the previous considerations, it appears likely that, for domestic consumption, most electrolyzers will be of grid-connected type, even if located next to hydrogen consumption centre or next to RES generation plant. This is both because of the higher flexibility of their operation (not constrained by local generation or local consumption patterns) and for the possibility to add revenue streams additional to selling hydrogen (such as power grid services, hydrogen market arbitrage and flexibility services provision). Therefore, when this technology will be deployed and upscaled to the GW level, the electrolyzers will have a significant impact on the power grid, deserving proper TSO positioning in scenario building, modelling, grid planning as well as grid operation.

Smaller electrolyzers, in the order of a few MW capacity and in the case of “hydrogen hubs” can also be grid connected, as their power sourcing should be able to rely also on grid power whenever the RES are not available.

On the other hand, for export-oriented electrolyzers, especially in areas where the electric grid is less developed, the base case will be off-grid typology.

### 4.1.8. Considerations on the localisation of electrolyzers

Establishing the location for hydrogen production may require a hybrid approach combining centralized and decentralized approaches. The costs associated with transporting hydrogen can be significant, particularly over long distances. Proximity to existing industrial infrastructure allows shared resources and services (e.g., water supply, strong power connections) and facilitates the integration of hydrogen into existing processes. If electrolyzers are sited near industrial users, all cost savings from reduced transportation can enhance the economic viability of hydrogen projects. Industries that require hydrogen (e.g., ammonia production, refining, and metallurgy) can utilize hydrogen directly, allowing for stable demand. This creates a more predictable revenue stream for electrolyzer operators. Furthermore, it must be considered that industrial facilities often require continuous hydrogen supply for processes. By situating electrolyzers nearby, operators can ensure a reliable feedstock, optimizing the electrolyzers' operational efficiency. Electrolyzers can adjust their output based on the hydrogen demand from the industrial users, maximizing production during high-demand periods and minimizing waste. In all cases, a small buffer storage might be needed as well.

By contrast, electrolyzers located near renewable energy sources (solar, wind) can directly utilize electricity generated during peak production periods that would not be directly dispatchable due to bottleneck in the electric grid. This reduces the need for energy storage solutions and mitigates renewable energy curtailments. Producing hydrogen close to renewable sources minimizes the carbon footprint associated with energy transport and reduces the emissions associated with fossil fuels used for power generation. The co-location of electrolyzers and renewable energy generation can accelerate the transition to a more sustainable energy system by demonstrating the viability of renewable hydrogen.

So, the correct approach should optimize production and usage and ensure a continuous supply of hydrogen while meeting safety requirements. The best planning location for electrolyzers depends on several factors, including the proximity to industrial usage and power generation. Placing electrolyzers close to industrial usage can reduce transportation costs and improve efficiency, while placing them close to electric power production can take advantage of renewable energy sources and reduce the need for new power lines.

In the perspective of grid planning, locating electrolyzers near to industrial plants entails the need to refurbish the electric network in the sections which feed the electrolyzers whereas the location of hydrogen production next to RES entails the necessity to create an extensive hydrogen network to transport it to the consumption locations. A global investments optimum policy should be enforced, taking a global system perspective, with possible synergies and competition between the investment in the different carriers. This can be done only if TSOs' investment plans start to be created in cooperation between gas, electricity and (in the future) hydrogen. On this aspect, TSO interoperability will be required to tackle possible issues tied with data exchange and coordination between the relevant planning offices. It must also be clarified that whenever the hydrogen network is to be created, either with new pipes or retrofitted ones, as for instance defined in the EU planning through the EU hydrogen backbone, it is easy to suppose that investment in hydrogen infrastructures could seem, at least in a first phase, economically disfavoured. However, here a long-term prospect should be assumed giving the right weight to decarbonization goals and to environmental externalities.

### 4.1.9. Advantages of starting with hydrogen valleys

Developing a hydrogen value chain requires acting both at the supply and at the demand side, as well as on the local logistics infrastructure linking supply and demand. To start with simpler, less CAPEX-demanding cases, probably the first investments will be realized in industrial conglomerates with clear and reliable off-takers and possibilities to build/reconvert industrial facilities to produce low-carbon hydrogen, the so-called hydrogen valleys, in EU, or hydrogen hubs in the US and other regions of the world. This will save the need to build upfront transport infrastructures, to set up direct commercial agreements allowing bankability of projects, as well as skipping the need to wait for having a full regulatory framework in place. Hydrogen valleys can be custom-tailored in terms of size, scalability, availability of energy sources and local logistics; they can be a first step for developing construction and operational experiences, as well as investment ecosystems and trading arrangements.

Hydrogen valleys are large-scale projects that go beyond piloting and demonstration stages. Creating hydrogen valleys offers several advantages as a first stage of hydrogen deployment policy. Since hydrogen valleys are equipped with their own renewable energy plants, they have a partial, but important, independence from the energy grid. Hydrogen valleys are also a synergistic infrastructure: by co-locating hydrogen production facilities with renewable energy sources, storage solutions, and end-users. In this way, hydrogen valleys can minimize infrastructure duplication and costs. For example, a hydrogen production site could share water supply and electrical connections with nearby industrial facilities. Electrolyzers can operate during periods of excess renewable energy generation, such as windy nights or sunny afternoons and provide grid services by adjusting their operation based on real-time electricity prices, helping to stabilize the grid and reduce the need for additional fossil fuel generation. Hydrogen valleys can be considered as regional ecosystems linking hydrogen production, transportation, and various end uses, facilitating local consumption and enabling the transportation of hydrogen overproduction to other sites where it is needed. They also reduce the need for battery storage and offer competitive costs for grid frequency control services. However, there may be trade-offs between the need to expand electric and hydrogen grids, which require careful planning and integration to maximize the benefits and minimize the drawbacks. They showcase the versatility of hydrogen by supplying more than one end-user sector or application in mobility, industry, and energy sectors. Hydrogen valleys cover multiple steps of the value chain from hydrogen production to storage, transport, and offtake, creating hydrogen ecosystems that cover specific geographies. The establishment of dedicated hydrogen pipelines within a hydrogen valley can facilitate efficient distribution, allowing for the connection of multiple users and reducing the costs associated with transporting hydrogen. Hydrogen valleys can stimulate hydrogen demand in end uses where electrification is not possible while simultaneously increasing renewable energy production from dedicated plants and excess renewable electricity production. They provide low marginal cost electricity for hydrogen production, reduce the need for battery storage, and offer competitive costs for providing FRR and RR services for grid frequency control.

However, careful consideration must be given to the trade-offs between expanding electric and hydrogen grids. Policymakers should prioritize investments that enhance the synergies between these systems, ensuring that the energy transition is efficient, sustainable, and economically viable. Hydrogen valleys can serve as a cornerstone in the transition to a hydrogen economy, providing a framework for integrating renewable energy, hydrogen technologies, and local consumption while paving the way for future growth and interconnections in hydrogen infrastructure.

If hydrogen valleys include a significant amount of internal RES generation matched with hydrogen production, once hydrogen self-consumption is satisfied, it could become economically rentable to develop a dedicated hydrogen network to sell surplus production and to connect it to future hydrogen grid backbones. In this way, the choice for future industrial plants using hydrogen either as a feedstock or as an energy vector is between installing their own electrolyzers or to import from the hydrogen grid, even with the possibility of establishing a power purchase agreement (PPA) with those hydrogen valleys that have a hydrogen production surplus. From the point of view of grid developers, in this way, electric and hydrogen grid development plans start to be in competition. Strong investments in the hydrogen grid favour the establishment of big RES-connected hydrogen production centres, which are then going to export production surplus by connecting to the hydrogen grid. By contrast, favouring a de-localized deployment of the electrolyzers strongly increases the need to invest in the electric grid nearby the industrial plants installing electrolyzers. The best compromise between these two policies should be sought by taking into account a global cost minimization target for the system (which includes both electricity and hydrogen) while ensuring a viable business case for investors, both those who intend to invest in hydrogen production and possibly export and those who could use hydrogen in the industrial processes. In a first phase of development of the hydrogen economy, this should also possibly include the need for an adequate level of state subsidies in order to stimulate the conversion to hydrogen of the industrial processes (which is presently hindered by too high costs for motivating both technologies replacement and hydrogen purchase) as well as the establishment of an adequate level of hydrogen offer. This would solve the typical chicken–egg problem of who has to start investing between the demand and the supply.

Hydrogen valleys are expected to become an important building block facilitating production, importing and exporting, distribution, transporting, and regional use of clean hydrogen in Europe and elsewhere in the world. A report on hydrogen valleys in [28] states that there are 81 valleys across the world and 67% (small-scale plants representing the true future value chain of hydrogen production) of the valleys are located in Europe (see Figure 1212).

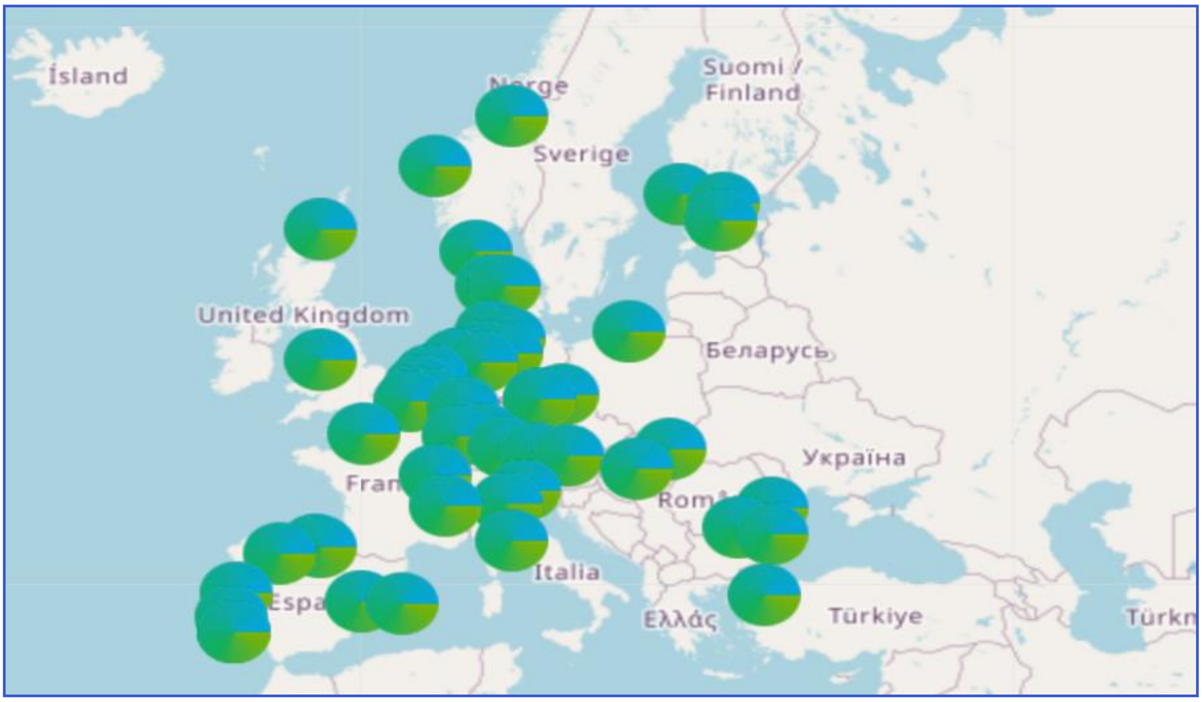


Figure 1212: Hydrogen valleys in Europe [28].

### 4.1.10. Holistic assessment of hydrogen projects requiring incentives

The analysis of location options and use cases show that, especially in first stage of development, P2H projects must be assessed with an end-to-end approach, in economic terms, energetic terms, decarbonization effect and cost-effectiveness versus alternative solutions. Focusing only on one piece of the supply chain (for example one isolated electrolyzer plant) falls short of assessing its system impact and viability. Supporting or even incentivizing a stand-alone part of the supply chain would be short-sighted and potentially far from optimal.

In order to guarantee sustainability and economic profitability, each project and each geography/industrial configuration needs a specific analysis, considering RES characteristics, transport and storage options (existing/prospected infrastructures), hydrogen destination features, as well as externalities (positive and negative) on adjacent sectors. This analysis, coupled with applicable energy policies in place, determines some areas as export-oriented, some as import-oriented, other areas as local-cluster oriented (hydrogen valleys), and others as not suitable for a hydrogen ecosystem.

In conclusion, the viability as well as the impact on electricity grids is case- and country-dependent, and no pre-determined conclusion can be applied until the use case has been analysed in its entire framework and boundary conditions.

## 4.2. Hydrogen sector impact on system development

*This section reviews the impact of the hydrogen sector beyond the pure grid perspective, enlarging to the development of the whole power system and also on the wider energy system, under a "System of Systems" integrated perspective. It focuses on the optimal use of energy resources, infrastructure, and the provision of long-term system services such as seasonal storage and strategic hydrogen reserves.*

### 4.2.1. Hydrogen demand impact on the power system

The primary physical interface between the hydrogen and electricity sectors consists of electrolyzer plants. A secondary interaction, though less prominent, arises from hydrogen-fuelled electricity generation plants. As such, the impact of hydrogen on the power system is strongly correlated with the number, capacity, typology, and location of electrolyzer facilities.

For a given hydrogen consumption level, a portion of the required hydrogen will be imported [9]. This share will rely on infrastructure such as ports, pipelines, shipping systems, and facilities for reconversion or regasification (e.g. from ammonia or methanol), thus placing minimal direct stress on the electricity system. The domestically produced fraction will include hydrogen produced via steam methane reforming with carbon capture and storage, future low-carbon technologies (e.g. methane pyrolysis), and a diminishing quantity of fossil hydrogen produced without CCS. These pathways do not involve the power sector directly. The remainder will originate from electrolyzers. Some of this electrolytic production may be off-grid, relying on dedicated renewable energy sources, thereby producing no direct impact on the electricity network. The significant implications for the power system arise specifically from on-grid electrolyzers. Among these, some may be situated within hydrogen valleys, where localized production and consumption reduce the need for hydrogen transport infrastructure and only partially affect the electricity grid.

Therefore, the principal direct impact on the power system derives from on-grid electrolyzer installations, both in terms of installed capacity (GW) and annual electricity consumption (TWh). These systems represent a new type of load and might prompt a substantial volume of grid connection requests. Scenario development for infrastructure planning must also account for the timing and scale of deployment, along with expected spatial heterogeneity, distinguishing between hydrogen-importing and hydrogen-exporting regions.

### 4.2.2. Scenarios and coordinated energy system planning

The geographic placement of on-grid electrolyzers is critical in determining whether electricity or hydrogen must be transported between renewable energy production sites and hydrogen demand centres. Electrolyzer siting might have significant implications for congestion in electricity networks, either aggravating or mitigating them.

To capitalize on potential synergies between the hydrogen and electricity sectors, coordinated planning involving electrolyzer developers and system operators is essential. Current procedures, which treat electrolyzers merely as industrial connection requests, are inadequate for this purpose. System planning frameworks must evolve to reflect the systemic importance of electrolyzers and their unique operational characteristics.

Future regulatory frameworks should therefore shift away from electricity-centric planning approaches towards integrated, multi-vector system planning, as this is necessary to ensure that the value and system-wide impacts of electrolyzers are properly reflected in the system development. Ultimately, the planning process must integrate electricity, gas, and hydrogen networks under a unified vision. The TYNDP of ENTSO-E [8] represents a first step in this direction, through initiatives like joint scenario building with gas network operators and multi-vector cost-benefit analyses. Further regulatory alignment and institutional coordination are required to fully operationalize integrated system planning.

A coherent and forward-looking planning framework must therefore extend beyond location considerations and incorporate systemic infrastructure design. The growing prominence of hydrogen in the EU's decarbonization strategy amplifies the urgency of this transition. While not all hydrogen will be produced domestically, a significant share will originate from domestic electrolyzers connected to the electricity grid. These installations will increasingly shape grid architecture and operation, reinforcing the need for integrated development strategies.

Given this development, it is crucial to design and implement an integrated and cost-efficient energy system that accounts for electrolyzers and supporting infrastructure. To achieve this, electricity infrastructure planning must adopt a multi-sectoral approach, incorporating both natural gas and hydrogen networks within a unified system framework.

In Europe, the *Hydrogen and Gas Markets Decarbonisation Package* [29] highlights the necessity of a more-coordinated planning process that integrates electricity, gas, and hydrogen networks. This approach seeks to enhance the cost-effectiveness of infrastructure development while facilitating cross-border energy exchanges. By adopting a multi-sectoral planning strategy, electrolyzers can be strategically located to minimize potential grid congestion and ensure cost-efficient energy transport via electricity and hydrogen networks.

From a resource allocation perspective, the priority should be to integrate electricity from RES into the power system wherever feasible. The decarbonization impact of displacing fossil-fuelled electricity generation through RES integration is considerably higher than its conversion to hydrogen via electrolysis. Consequently, both transmission and distribution networks must be reinforced to accommodate the increasing penetration of renewable energy and ensure system security.

The decision to convert electricity into hydrogen should be made dynamically, based on real-time system conditions. Ideally, electricity should be injected into the grid unless doing so would compromise system stability due to network congestion or oversupply. If electricity is converted into hydrogen when the grid could still absorb it, fossil-fuelled power plants may be required to compensate, ultimately leading to an increase in overall greenhouse gas (GHG) emissions. Therefore, the effectiveness of hydrogen in reducing GHG emissions is not automatic and depends on its interaction with the broader energy system. One mitigation strategy is the implementation of the additionality principle [30], ensuring that the electricity used for hydrogen production originates from dedicated renewable sources rather than displacing grid-integrated RES generation.

### 4.2.3. Infrastructure pathways

The transition towards a decarbonized gas sector is likely to follow two distinct, yet complementary, infrastructure pathways, progressing at different rates across regions.

*Hydrogen-based*

Hydrogen-based infrastructure, which will gradually expand alongside the existing methane gas network, enabling hydrogen to become a key energy carrier.

*Methane-based*

Methane-based infrastructure, where natural gas will be progressively replaced by renewable alternatives such as biomethane and synthetic methane, with potential blending of hydrogen in certain cases.

In Europe the *Hydrogen and Gas Markets Decarbonisation Package* explicitly aims to support this transition by facilitating the development of dedicated hydrogen infrastructure and markets, and fostering an integrated planning framework that connects electricity, gas, and hydrogen networks.

Natural gas TSOs are well-positioned to act as key enablers in the development of the hydrogen economy. Their contribution stems from three main factors:

- Existing infrastructure, which can be repurposed or adapted to connect new hydrogen supply and demand centres.
- Technical expertise, encompassing the development, operation, and management of assets required for hydrogen transportation.
- Market knowledge and geographical presence, which facilitate the coordination of hydrogen supply and demand across different regions.

For natural gas TSOs to fully assume this enabling role, they must be granted regulatory and operational flexibility to participate across the entire hydrogen value chain. Collaboration with hydrogen producers, suppliers, and other stakeholders will be essential to constructing a well-functioning and competitive hydrogen market. Furthermore, grid planning principles that apply to electricity networks must also be extended to hydrogen infrastructure, ensuring that network expansion and integration follow a coordinated and efficient trajectory.

### 4.2.4. Integrating hydrogen systems with the power system

Resource and technology availability make hydrogen technology an attractive asset in power system operation context. Potential for electrolyzer flexibility in ancillary services markets, targeting short-term network services such as voltage control, congestion management and frequency services can bring a significant change with the growing proportion of RES generation. Electrolyzers can provide power system services other than the provision of inertia, release congestion management in an electrical network by the operation and control of multiple hydrogen electrolyzers integrated in the grid [31]. From the technology availability, the infrastructure gaps identified in the ENTSOG TYNDP 2024 [8] report related to hydrogen can in some cases also be addressed by energy infrastructure solutions in other sectors, such as the electricity sector or the natural gas sector. This applies to any infrastructure gap identification that focuses on a specific energy vector. For electricity ENTSO-E prepares the *Identification of System Needs* (IoSN) report, which is the equivalent of the ENTSOG report [32]. This growth presents unique characteristics such as weather-dependency, which leads to high ramping rates and forecast errors. The distribution of these resources occurs in smaller units, but these units often exhibit similar behaviour over a larger geographical area. There is also a need for using surplus generation during windy or sunny hours to compensate for other hours, as electricity cannot be easily stored in large quantities economically or with high efficiency. To minimize the quantity and CAPEX of new assets, operational synergies must be achieved, decoupling:

- RES production profiles from final demand profiles, through P2X and storage in other forms of energy such as molecules, heat, mechanical and chemical; and
- hydrogen production profiles from hydrogen final demand profiles, leveraging the higher flexibility features of molecules.

This is where planning, investment signals and operation come together in a conundrum of both energy efficiency and infrastructure efficiency targets, requiring an holistic view. The system will also need a fair share of backup power during hours of deficit in the electricity system. This backup power initially comes from natural gas and other sources, but later also includes hydrogen-fuelled generators, which are very inefficient energetically (double energy conversion plus storage and transport losses) but quite efficient infrastructurally, avoiding high over-installed RES capacity. The TYNDP has made a first, very preliminary evaluation, which should be analysed more deeply through cooperation between the gas and hydrogen sectors.

Given the interactions between the energy carriers, optimization can be achieved using the characteristics of each one. These could be based upon economics, efficiencies, adequacy, spatial requirements, public acceptance, energy mix policies, or other factors. It is recommended that regulators establish the framework in principle, demonstrating how this could be implemented and especially how, if done collectively, it will significantly enhance the impact on the political discussion and lend more credibility to such efforts. This collaborative approach is key to driving forward the necessary changes in the energy sector.

### 4.2.5. Cross-sectoral benefits of hydrogen production

The large-scale production of hydrogen is expected to rely on electrolyzers with capacities reaching hundreds of MW and eventually GW scale [33]. These electrolyzers will primarily be connected to the transmission network. The integration of large offshore and onshore renewable farms into the grid could, under certain conditions, lead to congestion on high-voltage lines. One critical factor in electrolyzer deployment is location selection, which depends on gas infrastructure constraints, environmental regulations, and proximity to hydrogen storage facilities, such as salt caverns.

Even when electrolyzers are located far from renewable energy generation sites, they can still interact with these sources. This allows for full-capacity operation during periods of surplus renewable generation and shutdown during peak electricity demand. Advanced control systems for integrated renewable energy-electrolyzer configurations already exist, enabling precise coordination of power injection and withdrawal from the grid. Such an approach enhances grid stability by mitigating overload risks while also offering economic advantages.

While large-scale hydrogen production is expected to be crucial for maintaining grid stability, smaller electrolyzers connected to distribution networks will also play a role. These systems, ranging from 100 kW to 10 MW, can support local hydrogen markets and help improve medium-voltage grid conditions. Variability in power generation, particularly from wind farms, affects voltage stability, which can degrade power quality for other consumers. Local electrolyzers, controlled via regulators in coordination with transformers, can counteract these fluctuations, ensuring better voltage regulation.

Beyond voltage stabilization, electrolyzers can provide additional grid services, such as power smoothing, ramp rate control, and load balancing. By acting as flexible, controllable loads, electrolyzers store surplus energy in the form of hydrogen, shaping renewable energy output to better match grid requirements. Moreover, individual wind turbines could be supplemented with fuel cells powered by stored hydrogen, enabling additional electricity generation when needed.

From a market perspective, hydrogen production can offer multiple services to power system operators, including:

- ancillary services for both transmission and distribution system operators;
- flexibility support for medium- and low-voltage networks; and
- an alternative to curtailing renewable generation at the request of grid operators.

### 4.2.6. Cross-sectoral benefits of hydrogen storage

Hydrogen storage, when deployed strategically, can enhance system efficiency by addressing both peak energy production and demand periods. This enables a more rationalized infrastructure design, reducing the need for oversizing electricity and gas networks to accommodate extreme load conditions. By mitigating short-term fluctuations and providing seasonal balancing, hydrogen storage contributes to a cost-effective and resilient energy system.

The integration of hydrogen storage into the broader energy system provides multiple benefits [34], particularly in electricity sector operations and investment planning:

- Reduction in operational costs, including:
    - lower renewable power curtailment, enabling better utilization of available generation;

    - improved congestion management, reducing network stress; and
    - decreased reliance on ancillary services, such as frequency and voltage control.
- Reduction in infrastructure investment costs, including:
    - lower required transfer capacity for both electricity and gas networks;
    - reduced investment to maintain security of supply standards across parallel systems; and
    - price stabilization in electricity markets, mitigating extreme price variability.

In the initial phase of hydrogen market development, supply-side variability will likely be the main driver of flexibility needs. Unlike industrial hydrogen demand, which is relatively stable and predictable, electrolytic hydrogen production relying on variable renewable energy sources will exhibit high fluctuations, requiring adequate storage capacity. Moreover, seasonal imbalances will emerge early in the transition, as renewable energy generation is typically higher in summer, while demand remains relatively constant throughout the year.

Over the long-term, if hydrogen adoption expands into buildings and power generation, the demand side might also require additional flexibility measures to manage consumption variability. Hydrogen storage is therefore assumed to play an increasingly strategic role in balancing the overall energy system.

The system-wide benefits of hydrogen storage will be highly dependent on geographical factors, particularly the availability of underground storage sites such as salt caverns, which are not evenly distributed geographically. Furthermore, the feasibility of integrating hydrogen storage with renewable generation will depend on the local availability and potential of RES. A coordinated approach to storage site selection, aligned with renewable availability, hydrogen production hubs, and demand centres, will be essential to maximize efficiency and minimize costs.

### 4.2.7. Strategic considerations for hydrogen storage localization

The localization of hydrogen storage infrastructure is influenced by multiple factors, which include the supply source, storage service requirements, interconnectivity between consumption hubs, and the availability of suitable underground storage sites. These elements collectively determine the optimal placement of storage facilities to ensure a cost-effective, secure, and flexible hydrogen supply chain.

Several key aspects must be considered when determining the geographical distribution of hydrogen storage.

*Hydrogen supply source*

The origin of hydrogen plays a fundamental role in determining storage needs.

- Hydrogen imports via terminals, whether in gaseous form, in liquid form or as derivatives (e.g. ammonia), will require dedicated storage at import hubs before distribution.
- In contrast, pipeline imports and domestic hydrogen production may primarily rely on underground storage or facilities situated at end-user sites and modal exchange hubs where hydrogen is transferred between transport modes.

*Demand for hydrogen storage services*

Storage is required to manage both supply-side variability, which is initially dominant and, at later stages, demand fluctuations as hydrogen consumption expands. Additionally, storage is critical for modal exchanges, where hydrogen is transferred between different transport vectors such as pipelines, trucks, barges, or rail.

*Deployment of hydrogen interconnectors*

The expansion of gaseous hydrogen interconnectors linking industrial clusters and major consumption centres will reduce overall flexibility requirements by diversifying supply and demand patterns.

- Greater interconnectivity ensures that hydrogen surpluses in one region can compensate for shortages in another, thereby lowering the need for localised storage capacity.
- Additionally, interconnection enables the integration of multiple flexibility resources, including storage, thereby improving system-wide efficiency.

*Availability of underground hydrogen storage*

Underground hydrogen storage represents the most cost-effective solution for large-scale gaseous hydrogen storage. However, its feasibility is constrained by geological conditions, with the most-suitable sites, such as salt caverns, concentrated in specific regions.

## 4.3. Hydrogen sector impact on grid operation and flexibility provision

This section reviews hydrogen sector impact on grid operation through:

- resource and technology operational modes of electrolyzers;
- short-term flexibility (at grid level); and
- long-term flexibility (at system-wide level).

*Short-term flexibility*

Short-term flexibility (at grid level) relates to electrolyzers' flexibility potential in ancillary service markets, offering short-term grid services as voltage control, congestion management and frequency services.

*Long-term flexibility*

Long-term flexibility (at system-wide level) addressing capacity planning challenge by optimizing hydrogen production over the system's lifetime, while also exploring the possibility of utilizing hydrogen transport and storage to enhance system flexibility in relation to grid updates, equipment degradation and to increase resilience.

### 4.3.1. Provision of flexibility

Electrolyzers can provide flexibility to the electricity system only if they are connected to the electricity grid. They will be competing with all other forms of flexibilities on the market (e.g., flexible power plants, flexible electricity demand, pump-hydro, thermal storage, batteries/electricity storage). To provide flexibility on the system level, the operational mode is essential. A trade-off between economic aspects (e.g., CAPEX, OPEX, load factor) of electrolyzers vs. system needs must be found in order to have a viable business case with win–win solutions. In any case, to provide flexibility to the power system, the hydrogen system must have flexible elements downstream of the electrolyzers (like a hydrogen grid or storage), to decouple:

- RES generation profiles from electrolyzers' infeed; and
- hydrogen production profile from hydrogen demand.

This double decoupling requires the presence of buffer elements on either side of the electrolyzer, which depends on connection type and operational modes.

### 4.3.2. Taxonomy of connection configurations

The type of connection of electrolyzers is highly relevant to this analysis. Figure 13 shows that there are three conceivable connection types:

*Connection close to hydrogen demand*

Connection close to hydrogen demand implies that it will require a power grid connection while hydrogen is consumed on-site, hence no connection to the hydrogen network is needed. This "on-grid" type is shown at the left of **Error! Reference source not found.**.

*Stand-alone electrolyzers*

Stand-alone electrolyzers would require a connection to both power and hydrogen networks. This is considered part of the “on-grid” type in **Error! Reference source not found.**.

*Connection close to the source of power supply*

Connection close to the source of power supply implies that a connection to the hydrogen network alone is required, and the electricity required for hydrogen production is available on-site. From the power grid perspective, this is considered an “off-grid” type since there is no direct impact on the public network (right part of Figure 13).

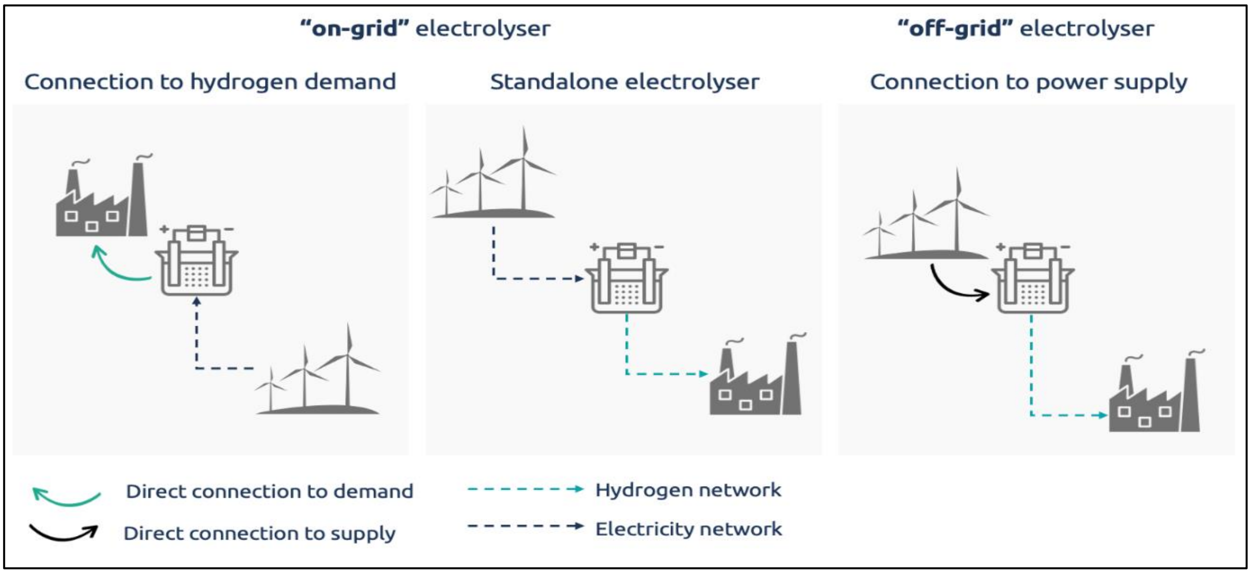


Figure 13: Types of electrolyzer connection with respect to the sources of supply and demand as well as the type of network. Source: own elaboration.

### 4.3.3. Taxonomy of operational modes

Several operational modes of electrolyzers can exist with different interactions and impact on the electricity system. Some of them need flexibility from the electricity system, further stressing the flexibility needs of the electricity grid, while others can provide flexibility to the electricity system (crucial for TSOs). A taxonomy of operational modes, seen from the grid operator perspective, is reported below. In practice, a combination of them, also changing over time, shall be applied, according to external factors such as electricity price, hydrogen prices, hydrogen storage options, both local and system-wide commercial needs as well as internal factors like company strategy, business case, and commercial production requirements.

*Demand-driven mode*

If there is no logistic flexibility on the hydrogen side, the electrolyzer has to follow strictly the hydrogen demand. The load factor depends on the client process and cannot exploit price opportunities nor provide electric flexibility. It is not straightforward to achieve 100% clean production.

*Baseload mode*

Due to high CAPEX determining the hydrogen price, investors will pursue high load factor. This is similar to or even more challenging than demand-driven mode as baseload operation increases the need for flexibility rather than providing it. Again, it is not straightforward to achieve 100% clean production 100%.

*RES-dedicated mode*

This mode matches RES generation available, as for off-grid electrolyzers or rigid PPA-based, guaranteed-100% renewable production. Since the hydrogen production profile is unrelated to hydrogen final uses profiles, logistic infrastructures are necessary, such as hydrogen storage, transport or ideally a pipeline providing both features. This creates a rationale for coordination among the hydrogen owner, hydrogen TSO, and electricity TSO.

*Market-based mode*

Electricity price drives the throughput, minimizing the OPEX component of the hydrogen price. In cases with their own RES (own RES plants or rigid PPA), in high price periods they can sell directly to the electricity market. In any case, there is an automatic intrinsic flexibility (demand response) even before or without a flexibility market transaction, supporting the system in smoothing peaks of surplus/deficit in the grid. Since the hydrogen production profile is unrelated to hydrogen final uses profiles, logistic infrastructures are necessary, as in the previous case, creating rationale for cooperation.

*System-supportive mode*

Priority is given to system needs, if well-remunerated, while the hydrogen production profile is following instead of driving the operation. This could be utilized in contingency situations or specific critical periods (alert for blackouts). As in the two previous cases, flexibility is needed on the hydrogen side.

Many combinations of the above operational modes are possible in real cases; for example, dedicating a portion of the capacity to flat long-term hydrogen off-takers, a portion to short-term and/or programmable hydrogen off-takers (final consumers or traders), a portion to hydrogen spot sales, complementing ancillary services provided to the grid.

Another important driver when choosing the operational modes, is the need to respect the criteria for low-carbon labelling; in Europe, these are, the additionality principle, time granularity (today one month but progressively reducing to one hour) and space granularity (bidding zone), aimed to ensure that RES-feeding electrolyzers are not blocked by grid physical constraints.

### 4.3.4. Taxonomy of use cases for grid operators

According to the impact on the power system operation, the previous cases can be summarized in **Error! Reference source not found.**. It is also very relevant whether storage elements (tanks, pipelines, caverns, consumer tanks, etc.) are present in the surrounding infrastructure ecosystem, either on electric side or on hydrogen side. This creates a buffer, which de-couples electricity input from hydrogen output, enabling flexible operation of the electrolyzers, benefitting the system while keeping its contractual obligations and so ensuring its business case.

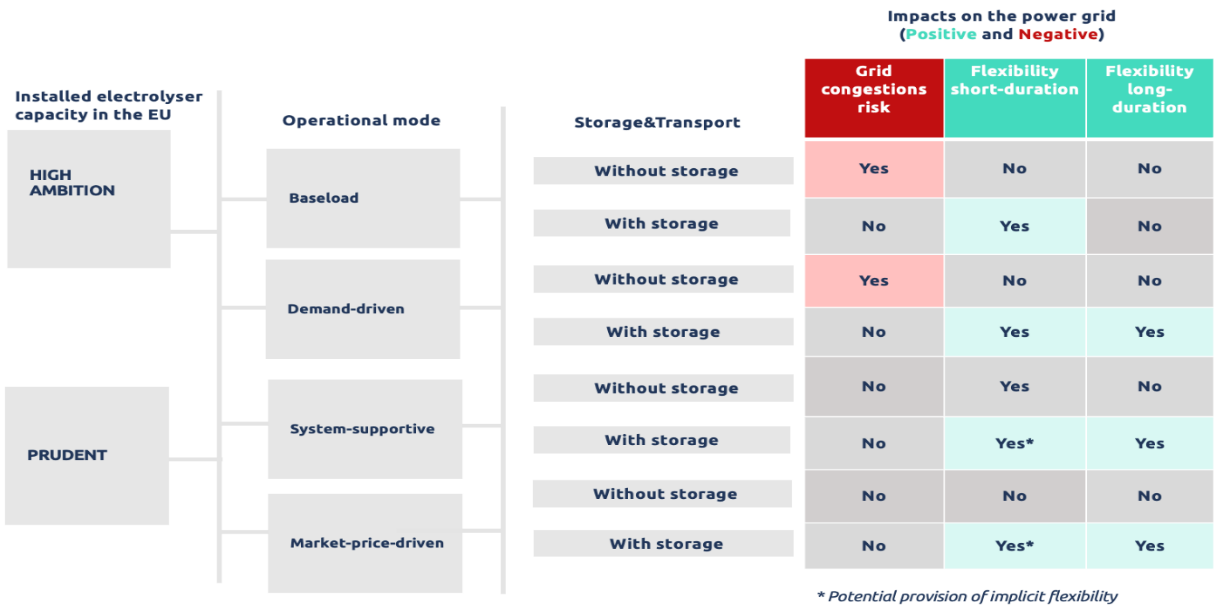

Figure 14: Positive and negative impacts on the power grid from different electrolyzer operational modes and their storage availability. Note that potential implicit flexibility is marked by * at the right-most-side. The storage is considered sized for evacuating the hydrogen production to, for example, a well-developed hydrogen grid. Source: ENTSO-E.

### 4.3.5. Grid operations and flexibility services provision

Electrolyzers, but more correctly P2H projects (end-to-end approach), shall impact on system operation.

For demand-driven P2H investments, the availability of a corresponding amount of RES, or at least the coordination of their growth with P2H time plans, may be an issue, especially if the additionality principle is strictly applied.

There is the possibility to provide system services such as mid- and long-term storage, seasonal reserve, cross-sector energy balancing, to be utilized by the system operator according to the efficiency and cost-effectiveness compared to other options, both within the electric system (hydro pumps, mechanical storage, compressed air, etc.) or in the surrounding energy sectors (in uses such as hot and cold thermal storage, water desalination and multi-fuels engines).

The latter duty, if still entrusted to the present grid operators, shall be particularly challenging, due to the complexity of interrelations of a sector-integrated system of systems and to the multiplicity of options to be actioned.

### 4.3.6. Improved design of electrolyzers for flexible operation

One aspect that is rarely discussed but is very important is the electrolyzer response speed to dynamic demand changes, low-load operation without negatively impacting gas purity, and reduced cold start-up time. Despite the adequate maturity of electrolyzers for industrial applications, those for energy applications are still under development and there is a large margin for improving investment costs, efficiency and service life; in particular, the performance in dynamic regime and the resistance to frequent start-stop cycles must be improved for use in this new field. This depends not only on the cell/stack, but also on the balance of plant. Consequently, low-hanging fruits could come from re-design or re-engineering of the process around the cell/stack, removing barriers to faster and deeper dynamic response. Furthermore, the possibility of reaching high operating pressures would bring other important energy and economic advantages. All these challenges could also be met by alkaline electrolyzers, currently under development. Even if PEMEL electrolyzers seem today the most suitable to be fed with a non-programmable renewable source, research and technological innovation could allow, in a reasonable time, alkaline and solid oxide technologies to also operate in a more flexible manner.

### 4.3.7. Hydrogen production impact on distribution grid

Hydrogen energy technology, through the flexible operation of electrolyzers, offers a promising solution for capacity planning and grid flexibility. The observed trends suggest a positive impact on grid stability and operational efficiency, reinforcing the value of integrating hydrogen technology into the distribution grid. The introduction of new loads will affect the distribution grid, necessitating flexibility from surrounding sources in the grid for mitigation and load shifting under high-demand periods [31].

The operational patterns for hydrogen production will have different consequences for the distribution grid, depending on the economic feasibility of production. Therefore, it is important to develop various scenarios and analyse the specific consequences for each case. By simulating hydrogen production from a specific grid, the impacts of importance would be clearer and optimal operation of hydrogen production could be more accurately defined. This could help to better understand the optimal ways to integrate hydrogen production into the grid as shown in Figure 15. As energy-intensive technology, electrolyzers can be operated to support the grid by regulating the input power based on the grid's condition, to deliver system services and participate in ancillary markets [35].

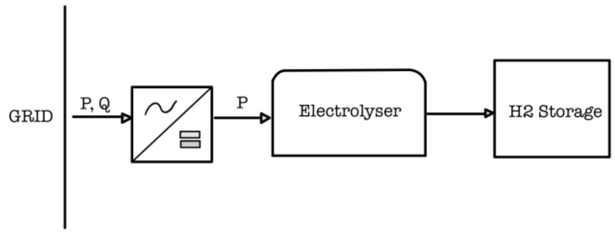


Figure 15: Layout for the grid-connected electrolyzer system. Source: own elaboration.

Different solutions such as energy storage, demand response, and curtailment of variable renewable energy sources in combination with hydrogen technology could be suggested to manage the energy flows and increase the flexibility of the grid considering the rapid dynamics of the electrolyzers.

The flexibility of an electrolyzer refers to its ability to adapt to different loading conditions, ramp up or down production quickly, start up quickly from both cold and warm states, and minimize standby losses. Cold start up is the time it takes for the electrolyzers to start up from ambient temperatures, while warm start up is the time it takes to start up when the system is already warm or in standby mode.

Heat is generated when an electrolyzer operates at lower loads, such as below 30% of its nominal capacity [36]. This can result in increased energy consumption and hydrogen production costs. At the other extreme, operating an electrolyzer above its nominal load, as is possible with PEMEL electrolysis, can cause the stack to degrade faster due to the additional stress of the overload. In addition, higher cooling costs may be incurred as more cooling of the system is required. Large electrolyzer systems composed of several modules can shut down part of the system completely, allowing for a wider practical load range. On smaller systems, the load range may be limited by the components that require cooling or heating to operate at thermoneutral conditions. The practical minimum load for alkaline electrolysis is around 20–25% of the nominal load. Operating below this level can result in increased impurities in the produced gases, and safety issues as the current density decreases, and the amount of contamination remains constant. Therefore, it is recommended to operate an alkaline electrolyzer near 100% of its nominal capacity. PEMEL electrolysis technology has better flexibility, as it can be operated across almost the full range from 0–100%, and in some cases even up to 120% for a short period of time. However, additional cooling and a properly dimensioned power supply is necessary to support operation in these overload scenarios.

From the technology behaviour point of view, as the enhancement in the start-up times can be expected in future, electrolyzers can be considered as a potential source of flexibility in the demand side of the power grid.

From the grid integration, hydrogen storage availability or dimensioning of a hydrogen storage facility is an important aspect. Therefore, it will be necessary for the different scenarios and feasible studies to explicitly examine the storage aspect. Utilization in terms of full load hours, at the low level of full load hours, may enable the electrolyzer to be available for grid services when needed.

The important fact is that producing hydrogen through electrolysis requires a reliable and resilient electricity grid. Distribution network operators might need more regulations in place to ensure efficient handling of bottlenecks and to maintain quality of electricity supply. The current trend of electrification is already putting the grid under strain and adding electrolyzers for hydrogen production will further increase the demand for upgrades. To avoid unnecessary upgrades to the grid, one alternative could be to design electrolyzers with some operational flexibility, allowing them to reduce their energy consumption during times of peak power demand. This comes at the cost of reduced hydrogen production, but optimal solutions may be found by maximizing the combined utility value of delayed grid reinforcements and the flexibility of electrolyzer operations.

### 4.3.8. Digital technologies and advanced control systems for flexible electrolyzer operation

The flexibility potential of electrolyzers will only be fully realized if supported by advanced digital control systems. Conventional industrial automation is not sufficient for GW-scale developments that must interact with volatile renewable generation, electricity markets and hydrogen networks simultaneously.

Hierarchical and distributed control architectures allow electrolyzers to respond at multiple timescales: from seconds (frequency control) to hours (market arbitrage) and days (hydrogen delivery scheduling). By coordinating data from grid operators, market platforms and hydrogen storage facilities, these systems optimize operation while protecting equipment life.

Digital twins and predictive optimization are emerging as essential enablers. They provide a virtual environment to test the interaction of electrolyzers with electricity, gas, and hydrogen networks before deployment, and they enable real-time optimization during operation. This reduces the risk of congestion, improves asset utilization, and lowers system costs.

Without such digital solutions, electrolyzers risk being treated as inflexible industrial loads rather than as grid-equivalent flexibility assets. With them, however, electrolyzers can become a cornerstone of integrated energy systems, supporting renewable integration, system resilience, and efficient infrastructure planning.

### 4.3.9. Summary considerations on flexibility expectations from hydrogen sector

Electrolyzers will likely be a new and important load for the grid, so they should contribute in terms of demand response. Technically, their rate of operation can be modulated to a certain extent, offering flexibility as demand response and balancing.

The flexibility potential depends mostly on the connection configuration, operational mode, as well as storage capacities in the hydrogen system to decouple electricity input from hydrogen output to final use.

Hydrogen can be stored seasonally, providing long-duration flexibility to the wider energy system, a very valuable service in a VRE-dominated future generation mix, where few alternatives exist (compressed air, thermal storage); however, location of storage facilities is unevenly distributed.

Making hydrogen a flexibility provider to the electrical system will require large structural investments beyond the electrolyzers, in hydrogen/synfuels pipelines/grids, storage and logistics.

## 4.4. Economic aspects of a new electrolyzer, considering also grid aspects

When assessing the economic viability of realizing an electrolyzer, attention should be given also to some aspects of its interrelations with the power grid in the connection point; in particular, the choice of technology should consider, among other parameters, the technical capability to provide grid services, as in the case study reported here below. Correspondingly, the business plan should contemplate on one side the benefits on supply costs deriving from its flexibility according to the selected operational mode, and on the other side the inflows coming from selling ancillary services to the grid operator at the connection point.

A case study for assessing the investment's economics of an electrolyzer is analysed in [37], and summarized here. Three scenarios and five different alternatives are compared, considering different electrolyzer technology, RES production typology, and battery systems, to identify which technology and system configuration maximizes hydrogen production efficiency at minimum costs, ensures the sustainable consumption of raw materials, as well as maximizing the grid hosting capacity.

The quantitative assessment uses smartgrideval software, an open-access tool developed by ISGAN, analysing three branches: the economic branch, the smart grid branch, and the externality branch. The most prominent solution obtained is to use hydrogen as storage and then this stored hydrogen can be used for grid services. This is further supported by the literature review, which shows that incorporating energy storage systems into electrical grids can increase the system's hosting capacity and mitigate the requirement for network reinforcement. This is primarily due to the rapid decrease in electricity production costs from RES. The results indicate that increasing RES share in the power system while maintaining constant electrolyzer power can improve the electrolyzer's capacity factor up to 53% and operating efficiency up to 90%. The proposed case studies show that the PEMEL electrolyzer configurations performed better than those associated with the AEL electrolyzer since it has a higher system and storage efficiency. This could make it easier to handle more power from RES and then use grid power when needed, thereby helping to prevent grid imbalance issues. This represents the first step in the study, as it is necessary to assess the positive impact of electrolyzers on the network and to choose the best electrolyzer technology. Future work will deal with modelling optimal electrolyzer configurations and testing them on real distribution networks to examine their effect.

# 5. Hydrogen market, is there any?

*The section aims to review any attempts at developing a hydrogen market. How do hydrogen market mechanisms influence the whole energy system? Which are the most-effective price signals for hydrogen suppliers/consumers?*

*Also, some considerations are made on the most efficient and effective ways to incentivize the early industry, balancing the need of positive business cases for private investors with maintaining fair regulatory environment with limited spending of public resources.*

## 5.1. Introduction

Unlike natural gas or electricity, hydrogen is not yet traded on exchanges and lacks standardized clearing mechanisms. As a result, trading activity remains limited and primarily takes place through bilateral agreements between suppliers and consumers. This is largely due to the early-stage development of the hydrogen market, which still lacks the necessary infrastructure and regulatory standardization [38]. Most hydrogen is produced and consumed on-site, and the absence of an organized and liquid market, with uniform rules and transparent pricing, reinforces reliance on direct agreements. While efforts are underway to establish standardized trading mechanisms and build supporting infrastructure, the market is still in development.

As part of the efforts to create an organized hydrogen market, the current focus lies in establishing supply chains from hydrogen producers to end-users, along with building the enabling infrastructure: production (e.g., electrolyzers), transport (e.g., repurposed gas pipelines), storage, and distribution to sectors like mobility and heavy industry. One of the main challenges in building these supply chains lies in scaling up the production of renewable hydrogen (produced through the electrolysis of water using renewable energy sources), which is expected to play a central role in decarbonizing hard-to-abate sectors. Despite growing investment announcements and many planned projects, only a small portion have reached construction or operational stages, resulting in marginal global production volumes. On the demand site, uptake remains limited, and without a balanced and liquid market (characterized by sufficient trading volume, multiple market participants, and transparent pricing), trading will continue to depend on bilateral agreements [39].

At this early stage, together with the absence of standardized product definitions, and certification schemes, a key complex dilemma arises as supply, demand, storage, and infrastructure must evolve in parallel [40]. Overcoming this requires proactive policy action to align actors, remove bottlenecks, and accelerate the establishment of a functioning and efficient hydrogen market.

## 5.2. Future design of hydrogen market: policy measures to ramp up the hydrogen economy

A future hydrogen wholesale market should function based on an accessible transport and storage infrastructure, similar to the natural gas market [41]. It could involve both physical trading, either through over-the-counter (OTC) transactions or exchanges with standardized products and clearing mechanisms, and financial markets offering hedging tools such as forward contracts and options.

Reflecting on the evolution of the gas market over the past decades can offer valuable guidance to better understand how the hydrogen market might evolve. For example, gas is traded in uniform thermal energy units (MWh); regardless of volume, it is valued based on its energy content [41]. This approach facilitates trade. Moreover, the success of gas markets has been driven in part by the development of virtual trading hubs, such as the title transfer facility (TTF) in the Netherlands and national balancing points (NBP) in the UK, which operate based on entry exit systems, allowing gas ownership to change multiple times while within the pipelines, increasing market liquidity and enabling more dynamic and efficient trading [42].

However, despite these structural similarities, hydrogen markets differ fundamentally from fossil fuel markets in one key respect. The value of hydrogen is not solely determined by its physical or energy content, but also by its environmental attributes, such as carbon intensity and the sustainability of its production and transport methods [39]. This means that, beyond upstream and midstream costs, the monetized climate benefits, like reduced $CO_2$ emissions, could play a critical role in pricing and trade dynamics [43]. Therefore, hydrogen trade could need mechanisms to capture and reflect these non-physical, environmental-value drivers, which adds complexity but is also a strategic opportunity for climate-friendly energy systems.

In light of the particular traits of the future hydrogen market, a sequential market development pathway is underlined by leading institutions such as IRENA [38] and the Hydrogen Council [43]. In the early stages of hydrogen market development, the absence of infrastructure and long-term investment certainty requires integrated projects and long-term agreements to support the entire supply chain development. Initially, there is a near one-to-one match between supply and demand, and price signals can begin to emerge. These early price signals may come from cost-based indices (e.g., Platts, Hydex [44]) and trading prices from pioneering projects and bilateral agreements (e.g., Hydrix [45]). Over time, hydrogen valleys will play a key role in early deployment by concentrating demand, enabling economies of scale, and supporting infrastructure development. As these hubs become interconnected and more participants enter the market, increased competition and standardization is expected to drive down costs and support the evolution from bilateral over-the-counter trading to standardized contracts and exchange-based markets with clearing mechanisms, following a trajectory similar to natural gas markets. These trends will be fundamental in the establishment of hydrogen hubs and structured, cross-border hydrogen trade networks [43]. Figure **Error! Reference source not found.**16 illustrates the expected development needs and market evolution in the coming years.

In this context, hydrogen exchanges will serve as a cornerstone of the future hydrogen market architecture. These platforms should enable structured, competitive, trading environments with standardized rules, pricing mechanisms, and transparent operations. They will also serve as a benchmark for market prices and provide tools for managing supply and demand risks. The future development of such exchanges will help facilitate cross-border trade, reinforce liquidity, and support investment certainty through predictable and transparent market conditions [45], [46].

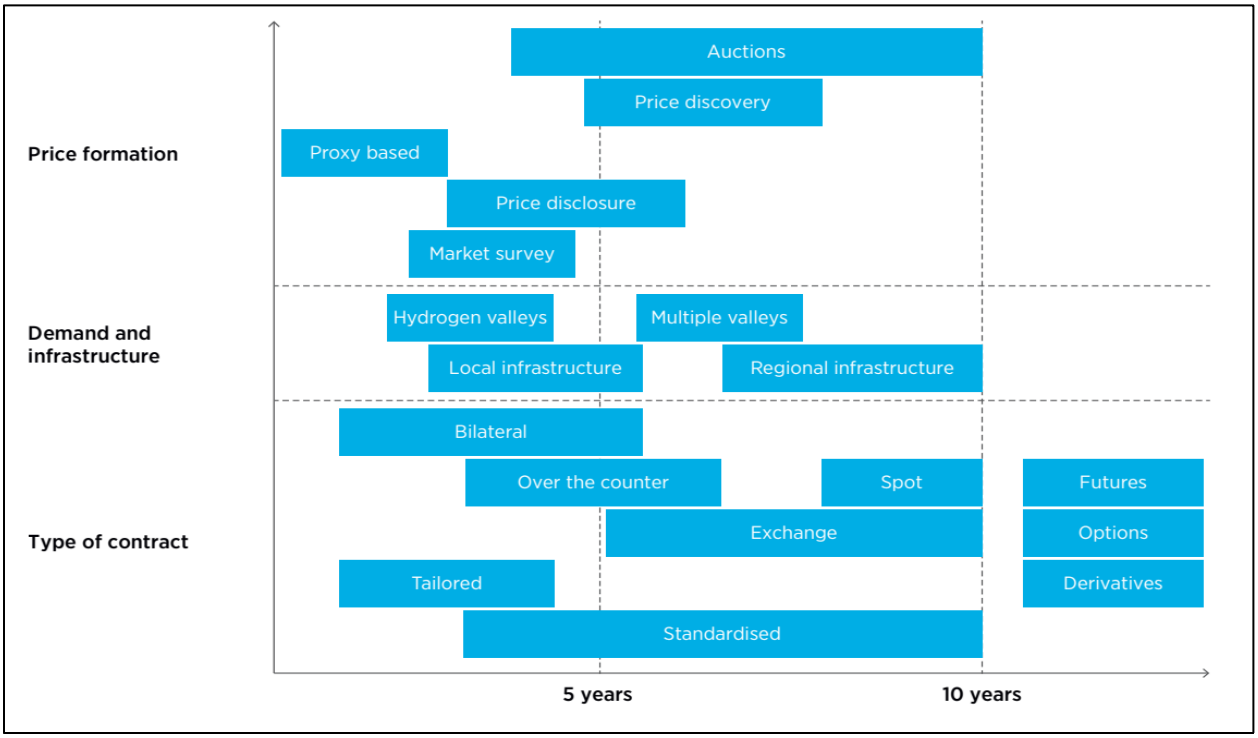


Figure 16: Expected development needs and market evolution in the coming years [38].

## 5.3. EU policy framework

The hydrogen market in Europe is still in its early stages. In fact, 88% of the hydrogen production capacity in Europe (equivalent to 9.85 Mta) is allocated for on-site consumption (i.e., captive hydrogen), and only 12% of the capacity (1.38 Mta) is designated for external distribution and sale (i.e., merchant hydrogen). In reality, just 29,767 tonnes of hydrogen were actually traded across European countries in 2023, a small share that is expected to gradually increase in the coming years [30]. The largest cross-border trade flow was from Belgium to the Netherlands, accounting for 19,272 tonnes, equivalent to 65% of all hydrogen traded in Europe. Other notable flows included the Netherlands–France (4.7%), Belgium–France (4.3%), France–Germany (4.1%), and Sweden–Denmark (3.9%). Together, these routes represented 82% of all European hydrogen trade in 2023 [31].

The EC has taken active steps to accelerate the development of a hydrogen market within the EU. Recognizing green hydrogen's potential as a cornerstone of decarbonization, especially in hard-to-abate sectors, the EU has introduced legislative and strategic frameworks to establish an efficient hydrogen economy.

A fundamental policy is the *EU Hydrogen Strategy*, adopted in July 2020 [36]. This strategy outlines the European Commission's vision for scaling up the production of renewable and low-carbon hydrogen and its integration across different sectors. The strategy emphasizes the creation of a unified European hydrogen market that fosters competition, cross-border cooperation, and ensures investment. It also promotes infrastructure development and regulatory frameworks to unlock hydrogen's full market potential. By 2030, the EU aimed to install at least 40 GW of electrolyzer capacity within its borders, supported by parallel investments in pipeline networks, storage systems, and cross-border trading mechanisms. The EU later sharpened the ambition, aiming for 10 million tonnes of domestic renewable hydrogen production plus 10 million tonnes in imports [47]. However, with only 216 MW installed in 2023, 1.8 GW expected by 2026, and most 2030 projects still in early stages, achieving the EU's hydrogen targets remains highly challenging [48].

Building on this strategy, in 2024, the EU adopted *Directive (EU) 2024/1788* [29], which sets out a common framework for the internal markets for natural gas and hydrogen. This directive is a key for the hydrogen sector, as it lays the legal foundation for commodity-based hydrogen trading and the creation of liquid-hydrogen trading hubs. It seeks to ensure competitive, customer-centred, flexible, and non-discriminatory markets, harmonize certification systems, and enable transparent price signals. As an example, the directive promotes the separation of network operations from activities of production and supply (i.e., vertical unbundling), as well as requiring that, where a hydrogen transmission network operator performs operation activities in the transmission or distribution of natural gas or electricity, it must be independent at least in terms of its legal form.

*Directive 2024/1788* directly aligns with the *EU Hydrogen Strategy* by facilitating the emergence of a competitive hydrogen market within the EU. Both the strategy and the directive emphasize the importance of transitioning towards a liquid market supported by commodity-based hydrogen trading, which is expected to encourage the entry of new producers, enhance integration with other energy carriers, and generate transparent price signals to guide investment and operational decisions. The directive sets out clear rules to support the creation of hydrogen markets and the establishment of liquid-hydrogen trading hubs. Principles that have proven effective in the electricity and gas sectors are considered, while acknowledging the distinct nature of the hydrogen market and the need to apply these principles in a way that reflects its current stage of development.

The EU has been a pioneer in creating a regulatory framework for the transition to carbon neutrality and the creation of a hydrogen market, reflecting an ambitious perspective. Several non-EU countries are also advancing national hydrogen strategies, such as Chile and Japan. Chile's *National Green Hydrogen Strategy* explicitly aims for international trade of green hydrogen [49]. The strategy sets ambitious targets, including producing the world's cheapest green hydrogen by 2030 and becoming one of the top three exporters of green hydrogen by 2040. Japan was the first country to adopt a national hydrogen strategy in 2017 [50]. The strategy focuses on building international hydrogen supply chains with countries like Australia, emphasizing green hydrogen production from renewable sources. The EU's commitment to developing market-based mechanisms, supported by clear legal frameworks and certification systems, will position it as a potential global leader in hydrogen trade.

## 5.4. Regulatory frameworks and market mechanisms affecting electrolyzer investments – the EU experience

The EU employs various policy mechanisms and subsidies to lower the CAPEX of electrolyzers, focusing on reducing initial investment barriers. Investment grants, tax incentives, and favourable financing conditions play a key role at both national and EU levels. The EU's *Innovation Fund* and *Important Projects of Common European Interest* (IPCEI) for hydrogen projects, such as Hy2Tech, Hy2Use, and H2Infra, provide substantial funding for early-stage electrolyzer projects, infrastructure, and industrial applications. Such initiatives are essential to establishing the hydrogen economy, especially during the ramp-up phase.

Concerning OPEX, mechanisms like PPAs and operational support schemes, such as hydrogen contracts for differences (H-CfDs), cap-and-floor contracts, or offtake agreements reduce costs and/or revenue risks associated with fluctuating prices or volumes. Indirectly, investments in hydrogen infrastructure, such as pipelines and storage, reduce transportation and storage costs, while regional hydrogen valleys link producers and users to simplify logistics, improving project economics. These measures are critical during the ramp-up phase, when infrastructure and demand remain limited and their development uncertain.

On the EU level, the first auction of the European Hydrogen Bank (EHB) in April 2024 allocated €720 million to seven renewable hydrogen projects, with winning bids averaging only 0.4 €/kg, far below the subsidy ceiling of 4.5 €/kg. The projects are concentrated in regions with competitive renewable resources, like Iberia and the Nordics, highlighting the critical role of location in cost efficiency. If similar outcomes persist in the second auction, the EHB's €3 billion budget could enable about 0.7 MT of renewable hydrogen production annually by 2030, linked to 6 GW of electrolyzer capacity. The auction results also underscore the impact of regulatory exemptions, as winning projects can use pre-subsidized RES capacity until 2038, reducing CAPEX needs.

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

### 5.4.1. The criteria for "green" labelling

To qualify as a renewable fuels of non-biological origin (RFNBO, corresponding to 3.32 $kgCO_2eq/kgH_2$) under the *Delegated Act (EU) 2023/118*, hydrogen production must adhere to strict criteria covering temporal and geographical correlation, as well as additionality.

*Temporal correlation*

Temporal correlation ensures alignment between hydrogen production and renewable electricity generation. Until 2029, hydrogen must be produced within the same calendar month as the corresponding renewable energy generation. From 2030, this rule tightens, requiring hydrogen production to occur within the same one-hour period as renewable energy generation or charging from a co-located storage asset. Some exceptions are possible when electricity market prices fall below certain values to reflect cases when electrolyzers operation would not involve fossil-based electricity production.

*Geographical correlation*

Geographical correlation requires RES to be located in the same or a connected bidding zone as the electrolyzer, with comparable day-ahead market prices or in an offshore bidding zone directly linked to the electrolyzer's location. Member States can implement additional geographical restrictions to align with their grid and hydrogen development strategies. Additionally, hydrogen production using grid electricity can qualify as renewable if the grid meets specific conditions: more than 90% of electricity consumption is RES-based, the bidding zone's emission intensity is below 18 $gCO_2eq/MJ$, or production helps reduce renewable energy curtailment.

*The additionality requirement*

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

*Guarantees of origin*

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

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

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

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

What this ultimately means is:

- Renewable hydrogen production targets might be hard to achieve at the desired scale and speed.
- Electrolyzer operators are unlikely to ensure that the produced hydrogen is fully renewable – unless they are co-located with dedicated RES.
    - Alternatively, hydrogen production would only occur depending on grid conditions, RES availability, and market prices.
- From the business-case perspective, electrolyzer operators are incentivized to be located close to demand.
    - Conversely, the regulatory conditions incentivize them to be located close to production, restricting operation to times when RES are abundant, at least before the establishment of a full-fledged hydrogen market and interconnected hydrogen infrastructure.
    - Lower capacity utilization and suboptimal efficiency would likely require higher subsidies or other mechanisms to be profitable.
- As such, a mixed impact is expected in terms of electrolyzers' flexibility potential.

A pre-condition for global trade of clean hydrogen around the world with import/export is that a global certification scheme for green or clean hydrogen should be in place, as well as a harmonization of eligibility criteria; for example, today the equivalent emission threshold is 3.38 $kgCO_2eq/kgH_2$ in EU, 4.0 in US, and 13.24 in China. The international partnership for hydrogen and fuel cells in the economy (IPHE) initiative launched at COP28 in UAE indicates *Technical Specification, ISO/TS 19870:2023 Hydrogen technologies — Methodology for determining the greenhouse gas emissions associated with the production, conditioning and transport of hydrogen to consumption gate* as the basis for a suite of four dedicated ISO standards on hydrogen production, conversion and conditioning, and transport of various hydrogen carriers.

### 5.4.2. Efficiency of support schemes, regulatory framework and other market arrangements in facilitating flexible operation

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

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

PPAs facilitate stable electricity costs and predictable revenue, essential for large-scale projects, but limit operators' ability to capitalize on low spot prices or provide system services.

Long-term hydrogen offtake contracts offer revenue stability and secure investment but restrict production flexibility and may lack upside potential.

Cap-and-floor contracts combine minimum revenue guarantees with upside potential during favourable market conditions, offering high economic efficiency and risk mitigation.

Reduced levies on renewable energy usage improve competitiveness by lowering operational costs but provide limited risk protection due to dependency on regulatory conditions.

Hydrogen GOs add moderate revenue benefits by certifying renewable hydrogen but impose constraints tied to RFNBO requirements, making operational flexibility low and risks dependent on market demand and regulatory changes. Each mechanism offers distinct advantages and trade-offs, highlighting the importance of tailored approaches to support electrolyzer projects.

Finally, H-CfDs reduce financial risks through stabilizing hydrogen prices, while offering moderate demand-driven flexibility. Note, however, that from the power system's perspective, to facilitate the most flexible operation of electrolyzers and ensure they are responsive to power system needs, H-CfDs might not be the most suitable way to incentivize cost-efficient flexible operation. Applied to an inherently flexible technology, these could risk creating controversial outcomes through incentivizing flexibilization while supporting baseload operation mode.

In summary, the following principles should be considered when designing support schemes.

- Avoid incentives to overproduce during low demand or grid constraints.
- Incentivize producers to align electrolyzer investments and operation with both electricity market and system signals (e.g., low electricity prices, grid congestion) and hydrogen demand signals. This could mean additional (locational) signals to reflect the energy system value of hydrogen production, also taking into account the impact on electricity grids and markets.
- Consider mechanisms to support hydrogen offtake and investment in hydrogen storage, ensuring the full value chain is incentivized, not just production itself.

# 6. Conclusion

The report reviews the impact of the integration of the hydrogen sector on the power sector through 1) power grid planning, 2) power system development, 3) power grid operation and 4) hydrogen markets, with potential future design and policy measures. In addition, it reviews national strategies and policies and existing regulations in example countries.

Key highlights:

- Electrolyzers will be a new and important component of the power system, thus short- and long-term grid planning should be strictly coordinated between power, gas and hydrogen sectors.
- Electrolyzers are capable of providing flexibility to grid operation. The flexibility potential depends mostly on the connection configuration, operational mode, and storage capacities in the hydrogen system.
- Flexibility is linked to attain a double decoupling: decouple electricity generation profiles from electrolyzer load profiles and decouple electrolyzer output from its final use profile.
- Hydrogen (both renewable and fossil-based plus CCS) can be stored seasonally, providing long-duration flexibility to the wider energy system. This is a very valuable service in a VRE-dominated future generation mix; however, location of storage facilities is unevenly distributed.
- Making hydrogen a flexibility provider to the electrical system will require large infrastructure investments beyond the electrolyzers, including hydrogen pipelines, storage and logistics.
- Hydrogen exchanges will serve as a cornerstone of the future hydrogen market architecture. The future development of such exchanges will help facilitate cross-border trade, reinforce liquidity, and support investment certainty through predictable and transparent market conditions.
- Hydrogen trading as a liquid market requires, beyond production and consumption diversity, global harmonization and certification of clean hydrogen eligibility standards.
- Recognizing clean hydrogen's potential as a cornerstone of decarbonization, especially in hard-to-abate sectors, the EU has introduced legislative and strategic frameworks to establish an efficient hydrogen economy.

Key message to regulators/policymakers:

- A proactive policy action is required to align actors, remove bottlenecks, and accelerate the establishment of a functioning and efficient hydrogen market.
- Mechanisms to support hydrogen offtake and investment in hydrogen storage should ensure that the full value chain is incentivized, not just the production side.
- Distribution network operators might need more regulations in place to ensure efficient handling of bottlenecks and maintain quality.

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# Appendix A: National strategies, policies, and existing regulations

*The section reviews how certain policies and strategies affect the transition to a hydrogen economy in both demand and supply sectors, import/export. It also reviews the national (if any) regulations of the listed below countries.*

## A.1 Sweden

### *A.1.1 National strategies and policies*

A hydrogen strategy is developed by Fossil Free Sweden [51], where hydrogen is a key enabler in 22 sectors in Sweden to be fossil free and contribute to achieving the climate goals. The strategy has been developed together with the companies and the various players acting in the hydrogen value chain. According to the hydrogen strategy, the cooperation between central government and the business sector is crucial. The hydrogen strategy provides a list of prioritized proposals for improving conditions for hydrogen development in Sweden as well as policy recommendation on the utilization of full potential of hydrogen. While Sweden has made progress towards enabling fossil-free hydrogen through national strategy proposals, capacity forecasts, and coordination assignments, many of these specific proposals have not been fully realized as formal government mandates or implemented policy, especially in the areas of regulatory reform, statutory planning targets, dedicated tax/tariff review outcomes, and structured production support schemes.

*Fossil-free hydrogen production dependent on the electricity system*

During 2021 the Swedish government had to assign a task to Svenska kraftnät (SvK) to develop an electricity network plan enabling electrification of industry sufficiently fast.

*Infrastructure for hydrogen development*

By 2022 the government had to set a goal to install 3 GW and 8 GW electrolysis capacity by 2030 and 2045 respectively. During 2021 the government had to task Swedish regulatory authorities (Energy Markets Inspectorate-EI) to develop regulation for hydrogen pipelines to ensure a revenue framework. It was recommended to review the law governing environmental permits.

*Fossil-free hydrogen dependent on the development of market conditions and regulations*

In 2022, the Swedish government had to review the taxation of hydrogen, including production and distribution. National recommendations for handling hydrogen and its pipeline had to be pulled up by The Civil Contingencies Agency (MSB), which had to be used by all rescue services.

*Fossil-free hydrogen initiatives in need of financial support*

The government in 2021 had to assign the Swedish energy agency to set up a call for proposals to test and demonstrate cross-sectoral hydrogen systems. In 2021, the government had to conduct a quick study to support fossil-free hydrogen projects through the carbon contracts for difference (CCfD).

*R&D as a key enabler of long-term sustainability in several hydrogen value chains*

The government should appoint a coordinating agency to increase the coordination between agencies related to permit issues. The government should ensure the universities and research institutes continue research and innovation in the hydrogen sector.

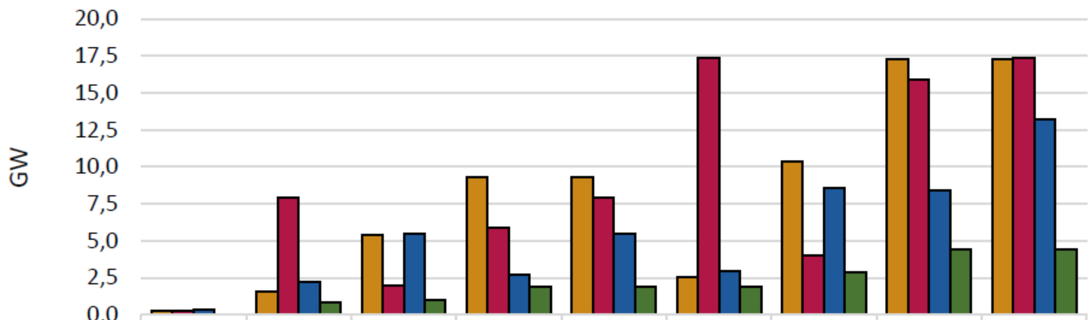
#### Hydrogen sector impact on electricity sector in Sweden

Sweden has set a goal of reaching net-zero emissions by 2045. The ongoing electrification of sectors where fossil fuels are used is an important part of climate work. Accordingly, fossil fuels will be replaced with electricity produced from fossil-free energy sources and this transition is expected to lead to a very large increase in electricity consumption over the next 25 years. The transport sector and large parts of industry are the sectors expected to be electrified in the future. In industry, the largest increase in electricity consumption is in the iron and steel industry, where the companies plan to convert all iron ore production to sponge iron produced with hydrogen through electrolysis.

Svenska kraftnät regularly updates long-term scenarios for the Swedish and Northern European power system. The scenarios are used to identify future challenges and needs in the Swedish transmission network and for the synchronous Nordic power system and enable a proactive approach. The work is called long-term market analysis (LMA) [52]. In the LMA report, greater emphasis than previously has been placed on modelling hydrogen production and distribution.

Overall, Svenska kraftnät sees a large increase in electricity consumption because of the electrification of the energy system. However, there are significant uncertainties in how large this increase in consumption will be, linked to the use of electricity by the fossil-free steel industry. In addition, there are uncertainties regarding the expansion of future electricity production, connected not only with profitability aspects but also legal aspects, such as permit processes for new electricity production, and technical aspects regarding, for example, lifetime extension of nuclear power plants. Depending on generation and consumption, the availability and need for flexibility to help balance the power system will be affected. The scenarios in LMA [52] are therefore differentiated based on electricity consumption, production mix, the flexibility that is assumed to be available, and the degree of expansion of hydrogen infrastructure in Sweden and Europe.

Assumed electrolyzer capacity in the Nordic countries based on the reference [53] is shown in Figure 17.




| | FM | SF | FM | EP | EF | SF | FM | EP | EF |
|---|---|---|---|---|---|---|---|---|---|
| | 2025 | 2035 | | | | 2045 | | | |
| Sverige | 0,2 | 1,6 | 5,4 | 9,3 | 9,3 | 2,5 | 10,4 | 17,3 | 17,3 |
| Danmark | 0,2 | 7,9 | 2,0 | 5,9 | 7,9 | 17,4 | 4,0 | 15,9 | 17,4 |
| Finland | 0,4 | 2,2 | 5,4 | 2,7 | 5,5 | 3,0 | 8,5 | 8,4 | 13,2 |
| Norge | 0,0 | 0,8 | 1,0 | 1,9 | 1,9 | 1,9 | 2,9 | 4,4 | 4,4 |

Figure 17: Assumed electrolyzer capacity for the Nordic countries year 2035 and 2045. “SF”, “FM”, “EP” and “EF” are different scenarios considered in the long-term market analysis in [52].

In the conducted analysis it is assumed that both Finland and Denmark have connections directly to the continent, to Estonia and Poland respectively. Norway is assumed to be connected to Denmark as there is already an existing natural gas pipeline, while there is an internal connection in Denmark between DK1 and DK2. Sweden is not assumed to be connected to the European hydrogen network in any of the scenarios, primarily because most hydrogen consumption is planned in northern Sweden, which does not have an existing gas network. Only Sweden and Denmark are assumed to have storage capacity [53].

## Hydrogen development impact on electric consumption

Figure 18 shows how electricity consumption in Sweden is assumes to develop for the scenarios from 2025 to 2050. The largest increase in consumption in the EP and EF scenarios is due to the big change in electricity consumption for hydrogen production.

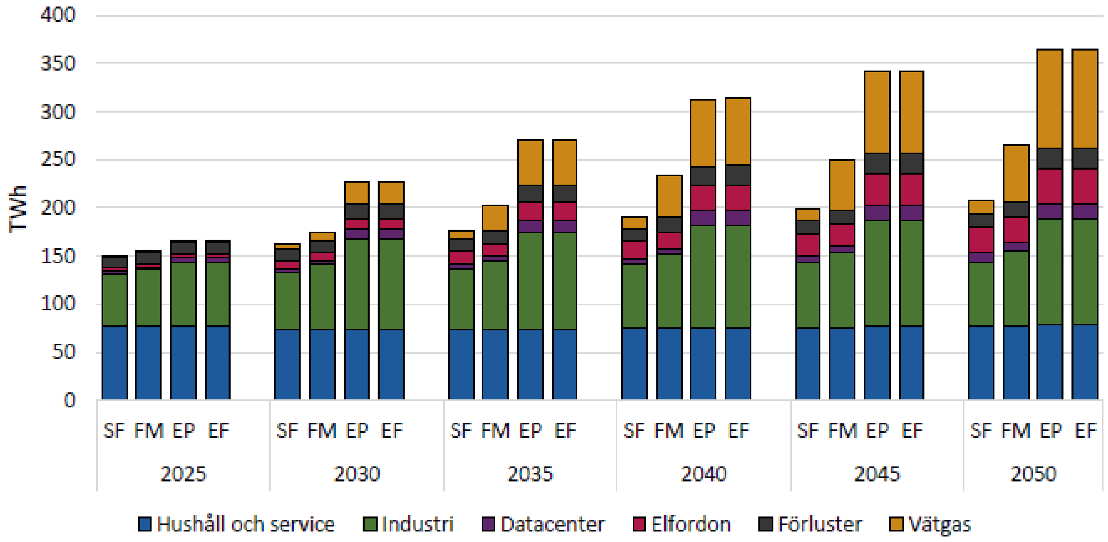



Figure 18: Electricity consumption in Sweden in all scenarios. Hushåll and service-household and service, Industri-Industry, Datacenter-data centre, Elfordon-EVs, Förluster-losses, Vätgas-hydrogen.

## Hydrogen development impact on transmission system

Swedish electricity production is mainly located in the northern part of Sweden, while Swedish consumption is in the southern part of the country; thus, most of the HV transmission capacity runs from north to south to transfer the electric power. To ensure secure operation of the electricity system Sweden is divided into four bidding zones (see left figure in Figure 19). The right figure in Figure 19 depicts future hydrogen production and use in Sweden. The figure shows that many projects focusing on fossil-free hydrogen via electrolysis are planned in SE1. If these projects materialize, this will significantly change the electric flow among the price zones in the future: SE1 will become an electricity import zone in contrast with its present state as an electricity export zone, as currently the electricity consumption in SE1 is much higher compared to the demand. This can be seen from Figure, which shows the simulation results from the long-term market analyses conducted by Svenska kraftnät [52], simulating the Swedish and Northern European power system with scenarios for reference years 2035 and 2045. Figure shows that currently the line SE2–SE3 is the biggest bottleneck in the system. However, all the anticipated changes in the power system in 2035 and 2045 entail power flow changes in the grid; accordingly, the line SE1–SE2 is expected to be heavily utilized and present the biggest restrictions in the system in all scenarios.

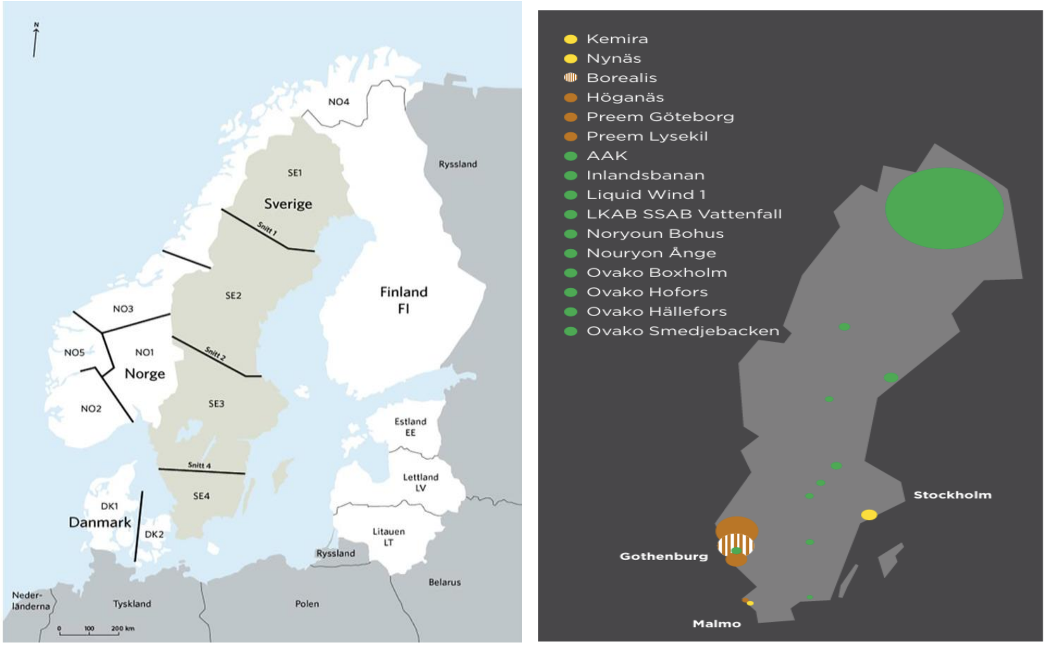



Figure 19: Left figure: Map of Nordic and Baltic bidding zones, 2022. Source: Svenska kraftnät. Right figure: Future hydrogen production and use in Sweden. Fossil-free hydrogen via electrolysis projects are green, a mixture of fossil-free hydrogen and blue hydrogen are brown, the projects where not only hydrogen is relevant are brown-striped.

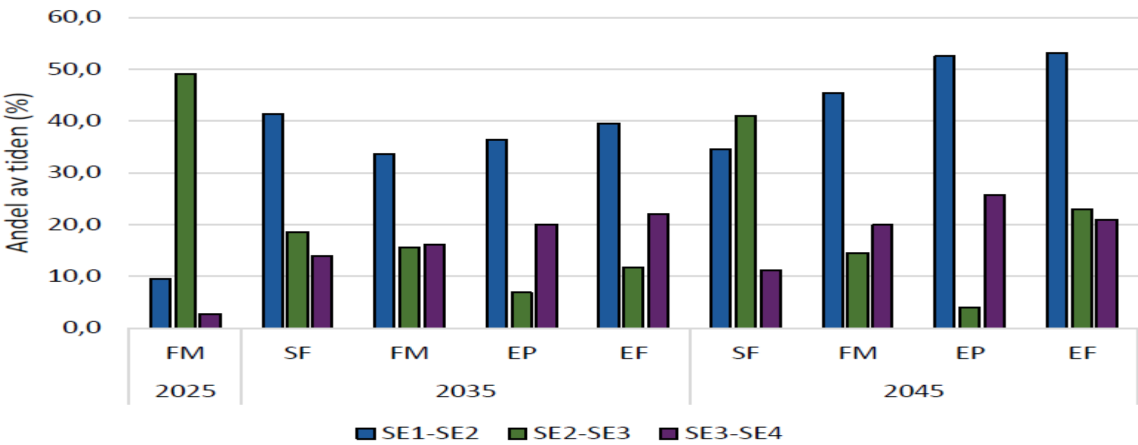



Figure 20: Percentage of time the transmission lines are expected to be congested between price areas in Sweden.

### A.1.2 National regulations

The Swedish energy agency has been assigned the task of coordinating the work on hydrogen in Sweden by the Swedish government. The purpose of the assignment is to facilitate an effective energy transition and to identify and remove the obstacles necessary for hydrogen to be used, produced, distributed, and stored in a satisfactory manner [54].

The task concludes that an updated regulatory framework is essential to enable the projected expansion of hydrogen. Between the interim report of March 2024 [55] and the final report of December 2024 [56], most of the key measures were retained, with increased focus placed on the role of the state, the importance of education of public and policymakers and the need to shorten project lead times.

### *New regulatory framework*

A new regulatory framework is needed for the hydrogen market to solve uncertainties such as permitting and the role of the state. The existing *Gas Market Directive* and *Gas Market Regulation* are solid building blocks from natural gas regulation and should be adapted and applied as quickly as is practicable.

### *Safety regulations and guidelines*

Some specific safety regulations and guidelines are identified as in need of updating:

- *Swedish Act (2010:1011) on Flammable and Explosive Goods* [57];
- the *Act (2003:778) on Protection Against Accidents* [58];
- the *Act (2006:263) on the Transport of Dangerous Goods* [59]; and
- the *Act (1999:381) on Measures to Prevent and Limit the Consequences of Serious Chemical Accidents* [60] (the "Seveso Act").

### *New supervisory area*

A new supervisory area for hydrogen infrastructure within the energy agency's oversight, required due to anticipated classification of hydrogen infrastructure as security-sensitive under the *Security Protection Regulation (2021:955)* [61].

### *Incentivization of additional hydrogen storage*

Incentivization of additional hydrogen storage is to be assessed to enable hydrogen's application to the electricity balancing markets.

### *Hydrogen taxation review*

Hydrogen taxation review is needed, including a minimum tax rate for hydrogen, in line with *EU Directive* [62].

### *Creation of a Hydrogen Transmission Network Operator (HTNO)*

Creation of a Hydrogen Transmission Network Operator (HTNO) is required to develop network codes and coordinate the joint planning of hydrogen and electricity networks.

### *Amendment to legislation*

Amendment to legislation is suggested for immediate effect to enable direct connection of hydrogen production to electricity generation, avoiding project delays due to the distribution network "concession requirements".

On 19 March 2024, the government submitted a proposal regarding the long-term direction of energy policy [63]. Within this were several key regulatory aspects.

- Existing legislation on pipelines [64], while not specifically developed for hydrogen infrastructure, is considered suitable for use and not an obstacle to hydrogen development.
- A review of regulation and policy instruments in this area is nonetheless recommended.
- The Swedish government has announced that the following principles should guide the future development of this sector:
    - The use of fossil-free hydrogen should contribute to the transition to fossil-free energy systems and industrial processes.
    - Hydrogen use should focus on applications that provide societal and economic benefits, where more resource- and cost-efficient alternatives are lacking.
    - Hydrogen production should be efficiently integrated with the electricity and heating systems and contribute to a secure energy supply in Sweden.

- Hydrogen infrastructure should be expanded in a way that facilitates climate transition while safeguarding Sweden's competitive energy prices.

### Permitting and environmental impact assessment

On 28 May 2024, the government proposed significant changes to permitting and environmental impact assessment [65], with the following key aspects.

#### *Simple amendment process*

Creation of the opportunity to consider new environmentally hazardous activities as an extension to an existing permit, saving time and money compared with requiring a new permit when new activities are identified.

#### *New extension process*

New extension process whereby time-limited permits can be extended once for up to three years.

#### *Streamlining*

It is recommended to increase the use of digital methods, creating a reduced route, avoiding the need for a main hearing and removing the role of the legal, financial, and administrative services agency (Kammarkollegiet) for some cases to speed up the process.

#### *Extended role for county administrative board*

An extended role is identified for the county administrative board. To gain more clarity from boundary consultations, the county administrative board's role will be expanded.

# A.2 Italy

## *A.2.1 National strategies and policies*

*The Italian National Hydrogen Strategy* [66] emphasizes the critical role of hydrogen in achieving Italy's decarbonization goals by 2030 and Net Zero by 2050, aligning with European policies and the PNIEC (*National Integrated Energy and Climate Plan*). The strategy outlines a mix of instruments for decarbonization, including increased renewable electricity, carbon capture and sequestration (CCS), biofuels, biomethane, potential nuclear power, and above all, renewable and low-carbon hydrogen. Hydrogen is seen as a key solution for sectors hard to electrify, such as industry and specific areas of mobility. Key aspects of the strategy include the following.

### Demand for Hydrogen

Focus on decarbonization of hard-to-abate sectors like steel, foundries, cement, glass, ceramics, paper, and feedstock (refineries and chemicals). The strategy considers scenarios with varying levels of hydrogen adoption, with potential long-term gross consumption reaching up to 11.93 Mtoe in a high diffusion scenario. Blending hydrogen with natural gas in industrial applications is seen as a potential initial step. In the transport sector e-fuels are expected to play a significant role to cover road (heavy-duty and long-range), rail, maritime (potentially through derivatives like ammonia and e-fuels), and aviation. In the high diffusion scenario, transport could account for over 30% of final energy consumption by 2050. For the civil sector hydrogen is not considered a priority, particularly where electrification is challenging.

### Power System Flexibility

To explore the potential of hydrogen for long-term energy storage and providing flexibility to the electricity grid, especially with high renewable energy penetration, the strategy prioritizes the full development of renewable hydrogen production while also acknowledging the potential contributions of blue hydrogen (with CCS) and hydrogen from nuclear sources. Importing hydrogen, particularly from regions like North Africa with potentially competitive costs, is deemed essential to meet domestic demand. The strategy outlines the development of the Italian hydrogen backbone as part of the European southern hydrogen corridor. Utilizing existing gas infrastructure and converting ports into renewable energy hubs are key elements. The development of a network of hydrogen refuelling stations (HRS) in line with the *Alternative Fuels Infrastructure Regulation* (AFIR) regulation is also a priority for the mobility sector. The importance of hydrogen storage, including the potential of converting natural gas storage sites, is highlighted for supply security and system flexibility.

## Strategic Actions, Policies, and Support Measures

To promote structural demand for renewable and low-carbon hydrogen in industry and transport through mechanisms like competitive procurement. Incentivizing domestic hydrogen production, particularly renewable fuels of non-biological origin (RFNBO) and biogenic hydrogen and fostering industrial scale-up. Establishing a "competition-based" mechanism for importing green hydrogen and its derivatives. Developing a comprehensive certification system for the origin, traceability, and sustainability of hydrogen. Simplifying regulatory and permitting procedures for hydrogen projects. Supporting research and innovation across the hydrogen value chain. Fostering the development of a national hydrogen supply chain and international partnerships. Emphasizing the role of R&D in enabling and accelerating the adoption of hydrogen technologies, focusing on sustainability, economic competitiveness, environmental protection, and energy security. Priority areas include improving efficiency, reducing costs, developing new materials, and integrating hydrogen into the broader energy system.

Entering into detail on the most relevant impacts of increased hydrogen demand and generation on the Italian electricity grid, the *Italian National Hydrogen Strategy* provides the following information.

### *Additional load in the system*

To produce the estimated hydrogen volumes, a substantial capacity of electrolyzers is necessitating a simultaneous development of additional RES capacity in a 1:3 ratio. This clearly indicates the anticipated additional load from electrolyzers.

### *Location of that additional load*

The document considers different locations for renewable energy generation and hydrogen consumption areas. It promotes the valorization and strengthening of hydrogen valleys, including those in port and airport areas, suggesting concentrated areas of electrolyzer load.

### *Flow of energy in the grid*

The strategy emphasizes the importance of coordinated development of the electricity grid and infrastructural projects for hydrogen transport. It discusses the need for sector coupling, where electrolyzers connected to the electricity grid can support the integration of new renewable capacity. The development of the Italian hydrogen backbone as part of the southern hydrogen corridor, connecting production and consumption centres, implies consideration of grid connection points.

### *Additional source of services to the electricity system*

The document explicitly addresses hydrogen's potential role as a flexibility resource for the electricity system. It states that long-term hydrogen storage could be valuable for providing flexibility in a context of very high renewable penetration. Surplus renewable electricity could be converted to hydrogen ($P2H_2$) and then used to supplement reduced renewable electricity generation, potentially through fuel cells or combustion in blending with biomethane or natural gas coupled with CCS. The document suggests that hydrogen can be partially used to generate electricity during opportune moments and as an energy storage tool.

## Criticalities implied by grid-connected electrolyzers

Regarding the criticalities implied by grid-connected electrolyzers, the following aspects are highlighted.

*Possible connection issues*

The document acknowledges the need for coordinated development of electricity grid and hydrogen transport infrastructure. While it does not detail specific connection issues, the emphasis on grid reinforcement and coordinated planning implies an awareness of potential challenges related to location, capacity, and grid reinforcements. The strategy also mentions the need to consider the impact on network infrastructure.

*Need for coordinated grid planning within hydrogen valleys*

The strategy explicitly mentions the valorization and strengthening of hydrogen valleys, suggesting an integrated approach. It also discusses the development of private hydrogen networks within these valleys, implying a need for considering their interaction with the broader energy system and avoiding regulatory constraints that hinder their development.

*Necessity to account for the additional electric load*

This is directly addressed by the recognition that hydrogen production will increase electricity demand and the need for additional renewable generation capacity. The document emphasizes the importance of efficient sector coupling with RES generation and even mentions introducing policy measures for a liquid hydrogen purchase agreement (HPA) market and reducing electricity procurement costs for electrolytic hydrogen. Studying use cases for consumption profiles is not explicitly mentioned, but the analysis of different production and consumption models serves a similar purpose.

*Need to analyse dynamic characteristics and the interactions with the wider electric system*

While the document does not explicitly use the terms “stability simulations” or “control and protection schemes,” the discussion of hydrogen’s role in providing flexibility to the electricity system and sector coupling implies that the dynamic interaction with the grid is a relevant consideration. The need to integrate hydrogen production into the energy system effectively also suggests the importance of analysing these interactions.

*Analyse the capability to provide ancillary services*

The strategy discusses hydrogen’s potential to offer flexibility services to the electricity system in the context of high renewable penetration. This aligns with the concept of providing ancillary services like frequency and voltage support, demand response, and flexibility provision. The document mentions that this would be utilized by the grid operator based on efficiency and cost-effectiveness compared to other flexibility means.

The location of electrolyzers is discussed implicitly through the lens of territorial models and the concept of hydrogen valleys, suggesting locations next to consumption sites (industrial hubs, ports, airports). The document also considers production in areas with high renewable energy potential (implying next to generation sites, potentially in the south of Italy) with subsequent energy transport. The possibility of electrolyzers in any generic point of the meshed power grid is also plausible given the discussion of grid-connected electrolyzers and their role in sector coupling and providing flexibility.

### *A.2.2 National regulations*

Italian national regulation for hydrogen is fully in line with the European regulation presented in Section 5.4.

## A.3 Belgium

### *A.3.1 National strategies and policies*

Belgium’s federal hydrogen strategy [67], first presented in October 2021 and updated in October 2022, presents the federal government’s ambition to strengthen Belgium’s position as an import and transit hub of hydrogen. Hydrogen, particularly in its renewable form, is positioned as a critical vector for decarbonizing sectors that are hard to electrify, while also playing a vital role in energy storage and security. Given Belgium's limited renewable energy potential, the strategy emphasizes hydrogen imports, technology leadership, market structuring, and international cooperation. In this regard, the strategy is structured around four core pillars, each aimed at supporting different stages of the hydrogen value chain and facilitating Belgium's hydrogen economy.

*Positioning Belgium as an import and transit hub for renewable hydrogen*

Recognizing that domestic renewable resources are insufficient to meet long-term energy needs, Belgium plans to import between 200 and 350 TWh of hydrogen and hydrogen derivatives by 2050, positioning itself as an import and transit hub for hydrogen in Western Europe. Key import routes are considered: The North Sea route leverages the region's strong offshore wind potential, enabling cost-effective hydrogen production. The Southern route aims to establish a pipeline corridor from Southern Europe and North Africa, although this will require more time due to infrastructure needs. Meanwhile, the shipping route focuses on importing hydrogen derivatives such as ammonia and methanol via ship, using Belgium's advanced port infrastructure to facilitate delivery. Together, these routes will ensure diversified, resilient access to renewable hydrogen for both domestic use and transit to neighbouring countries. The federal government is advancing Belgium's hydrogen infrastructure by building import terminals, strategic storage, and expanding the national pipeline network (targeting 100–160 km of pipelines by 2026) and full interconnection with Germany, France, and the Netherlands by 2028.

*Expanding Belgian Leadership in Hydrogen Technologies*

Belgium hosts a dense network of research institutions, companies, and technology developers active across the hydrogen value chain, from production to end-use integration. To strengthen this network, several R&D initiatives have been funded through several targeted programmes. For example, the *Energy Transition Fund*, active since 2017 until 2025, has issued annual calls totalling €20–30 million per year, to support, among other topics, innovation in hydrogen technologies. Moreover, the *clean hydrogen for clean industry* call focuses on the development of high-maturity technologies for the production and use of hydrogen. Additionally, the *hydrogen import* call aims at advancing technologies related to hydrogen import and grid integration. The federal government also supports the development of the VKHyLab, a dedicated hydrogen test facility designed to support the scaling and demonstration of new hydrogen technologies. Collectively, these measures aim to position Belgium as a hub of technological excellence and commercial readiness in the hydrogen sector.

*Establishing a Robust Hydrogen Market*

A key pillar of Belgium's hydrogen strategy is the creation of a robust, transparent, and efficient hydrogen market. This involves addressing both demand and supply challenges by promoting hydrogen use in hard-to-electrify sectors such as industry, heavy transport, aviation. On the network side, Belgium is expanding its national hydrogen transport network through new and repurposed pipelines, ensuring regulated third-party access. Efforts are underway to establish a certification system, market platform, and gas quality standards. These initiatives are designed to build market confidence, reduce investment risk, and foster a competitive hydrogen market

*Fostering National and International Cooperation*

The final pillar of Belgium's hydrogen strategy underscores the importance of collaboration at all levels. Nationally, coordination between federal and regional governments ensures policy alignment, while at the European level, Belgium engages in forums like the North Sea Energy Cooperation to support infrastructure and regulatory integration. Internationally, it is forming partnerships with countries such as Oman and Namibia to secure hydrogen imports. The strategy also backs the creation of the Belgian Hydrogen Council [68] to unify stakeholders and promote Belgium's hydrogen interests globally.

The Belgian hydrogen strategy supports the achievement of a climate-neutral energy system by 2050. By including hydrogen in its decarbonization pathways and by developing robust infrastructure and market mechanisms, this strategy paves the way for a system-wide transformation. This strategy has been reflected in a variety of Belgian initiatives, particularly in the areas of infrastructure development, hydrogen integration within broader energy systems, and international collaboration. The following are some of examples of relevant initiatives.

*The ReInvent project*

The ReInvent project [69] investigates how sector coupling (i.e., integration of different energy carriers such as electricity, heat, and molecules) can be effectively integrated into Belgium's energy system in a cost-efficient and sustainable manner. It aims to support the transition towards a low-carbon future by examining how these energy vectors can be coordinated across supply and demand, infrastructure, and market design. This aligns with the federal strategy's emphasis on planning a multi-energy system where hydrogen plays a complementary role to electrification.

*The Hydrogen Import Coalition*

The Hydrogen Import Coalition, involving partners like Fluxys, Port of Antwerp-Bruges, DEME, ENGIE, Exmar, and WaterstofNet, has assessed the technical and economic feasibility of importing green hydrogen and its derivatives into Belgium via shipping [70]. This initiative directly supports the federal strategy's focus on developing the Shipping Route for hydrogen imports and establishing Belgium as a hydrogen gateway for Europe. The coalition's findings confirm that importing hydrogen carriers is both technically viable and strategically important for meeting future Belgian and European energy needs.

*PATHS2050*

PATHS2050 is a strategic coalition coordinated by VITO-EnergyVille that provides in-depth scenario analyses for Belgium's transition to a climate-neutral energy system by 2050 [71]. Rather than focusing on a single technology or energy carrier, the project explores multiple integrated pathways that consider evolving energy demand, sectoral developments, infrastructure requirements and future plans. It assesses the roles of electrification, renewable energy sources, molecules (including hydrogen), and energy efficiency across different sectors of the economy. The approach of the coalition aligns with the federal hydrogen strategy's goals of system-level planning, highlighting where and how hydrogen can complement other vectors within a coherent decarbonization framework.

*WaterstofNet*

Lastly, WaterstofNet plays a central role in supporting hydrogen deployment in Flanders and in the Netherlands [72]. It facilitates public-private partnerships, project coordination, and cross-border collaboration. In line with Pillar 4 of the federal strategy, which stresses the importance of cooperation, WaterstofNet, together with Cluster Tweed, leads the Belgian Hydrogen Council [68]. This council brings together key players in the hydrogen ecosystem to advise policymakers and promote Belgium's hydrogen expertise at the international level.

For a broader view of Belgium's growing hydrogen landscape, a wide range of ongoing and planned hydrogen initiatives are presented in the Belgian Hydrogen Council website [73]. This resource provides an up-to-date overview of national projects, infrastructure developments, and stakeholder engagement throughout the hydrogen value chain.

## A.3.2 National regulations

Belgium has taken important regulatory steps to support the development of a hydrogen economy, with a growing focus on infrastructure and coordinated market development. As hydrogen is expected to play a central role in decarbonizing hard-to-electrify sectors and enabling energy system integration, the country is actively shaping policy frameworks to facilitate its efficient deployment.

A key development in this context is the establishment of a regulatory framework for hydrogen transport [74]. This hydrogen law introduces essential provisions to ensure that hydrogen transport infrastructure is developed in a way that mirrors the existing structure for electricity and gas. The law regulates, for example, the designation of a hydrogen network operator (HNO), guarantees non-discriminatory third-party access to the hydrogen transport network, defines the rules for preparing the network development plan and setting the network tariffs, and designates the Commissie voor de Regulering van de Elecktriciteit en het Gas (CREG) as the regulator for hydrogen transmission.

Following the Hydrogen transport law, Fluxys Hydrogen was officially appointed in April 2024 as the hydrogen network operator (HNO) for Belgium [75]. In this role, Fluxys will be responsible for the development, operation, and maintenance of the national hydrogen transport network. The appointment is a critical step towards building an open-access hydrogen backbone that connects key industrial zones, ports, and cross-border entry and exit points.

These legislative initiatives are also reflected in Belgium's updated *National Energy and Climate Plan* (NECP), submitted in 2023 [76]. The draft NECP highlights the country's ambitions to become a hydrogen import and transit hub in Europe and outlines several priorities for hydrogen deployment. These include the expansion of hydrogen infrastructure, integration with electricity networks, support for innovation and industrial uptake, and participation in cross-border cooperation platforms. The NECP also stresses the importance of coordinated certification schemes and market design rules at both national and EU levels to facilitate the rollout of renewable and low-carbon hydrogen across the continent.

These regulatory instruments and policy plans signal a structured and forward-looking approach to hydrogen in Belgium. Providing the initial policy certainty needed for infrastructure investment, ensuring fair and efficient market functioning, and reinforcing Belgium's strategic position as a key player in the European hydrogen transition.

## A.4 Spain

### A.4.1 National strategies and policies

Spain's *National Renewable Hydrogen Roadmap* [77] defines a comprehensive strategy to establish a competitive and technologically advanced hydrogen economy by 2030. Aligned with the *European Green Deal* [78] and Spain's *Integrated National Energy and Climate Plan* (PNIEC) [79], the document positions renewable hydrogen as a pivotal vector for achieving climate neutrality, energy security, and industrial modernization. It sets forth a coordinated approach combining regulatory measures, targeted investments, and innovation support to facilitate the decarbonization of sectors where electrification remains technically or economically unfeasible, particularly industry and heavy-duty transport.

The roadmap outlines a three-phase timeline for the deployment of renewable hydrogen technologies. The initial stage (2020–2024) is dedicated to building foundational capacity, with a target of 300–600 MW of electrolyzers co-located with major industrial consumers. This stage also includes the development of hydrogen valleys and pilot projects leveraging local renewable generation. The second phase (2025–2030) scales up deployment to 4 GW, focusing on sectoral integration, infrastructure expansion, and the creation of a resilient supply chain. In the final phase (2030–2050), mature hydrogen technologies are expected to be deployed at scale, contributing to energy storage, synthetic fuel production, and full-sector decarbonization. By 2050, up to 25% of Spain's renewable electricity may be channelled into hydrogen production.

#### Demand

Spain anticipates a rapid growth in domestic hydrogen demand, with key applications concentrated in hydrogen-intensive industries such as oil refining, ammonia and fertilizer production, and the metallurgy sector. Heavy transport, including buses, trucks, and freight logistics, represents an additional growth vector. The 4 GW electrolyzer capacity targeted for 2030 is designed primarily to serve domestic demand, underpinning industrial decarbonization and fostering energy independence.

#### Grid flexibility and energy system integration

Hydrogen production is framed as a tool to provide flexibility to the power system, enabling better integration of variable renewable energies. Electrolyzers are recognized for their potential to absorb surplus renewable generation and mitigate curtailment, particularly during periods of excess solar and wind production. Their flexible operation is also acknowledged for enhancing grid stability, also enabling long-term storage and sector coupling, linking electricity, gas, and industrial systems.

#### Infrastructure challenges and grid integration constraints

The large-scale integration of grid-connected electrolyzers may entail technical and regulatory challenges. Key concerns include the assurance of renewable electricity sourcing for hydrogen certification, risks of local grid congestion, and the need for advanced digital monitoring systems to synchronize production with renewable availability. Furthermore, the roadmap calls for clear regulatory pathways for the participation of electrolyzers in electricity markets and their potential provision of balancing and demand-response services.

#### Instruments for market activation

To support the hydrogen transition, Spain has adopted a broad set of instruments spanning regulatory, financial, and industrial domains. These include public funding schemes such as the *Recovery, Transformation and Resilience Plan (PERTE) for Renewable Energies, Hydrogen and Storage* [80]; streamlined permitting processes; and the implementation of guarantees of origin for green hydrogen. The strategy promotes the development of hydrogen valleys as innovation clusters and foresees dedicated support for research, pilot projects, and the scaling up of Spanish industrial capabilities across the hydrogen value chain.

#### Strategic electrolyzer localization

The roadmap prioritizes the co-location of electrolyzers near major hydrogen demand centres, such as refineries, fertilizer production plants, and chemical complexes, where existing grey hydrogen consumption can be directly substituted by renewable alternatives. Furthermore, it advocates for the development of hydrogen valleys, or regional clusters, to be supported by direct access to local renewable electricity sources, thereby reducing reliance on grid infrastructure and ensuring compliance with renewable origin certification. Regulatory proposals also encourage the simplification of permitting processes for direct power lines and dedicated hydrogen pipelines, highlighting the importance of geographical proximity between production and consumption sites to avoid grid congestion.

### A.4.2 National regulations

The regulatory framework for renewable hydrogen in Spain is gradually converging towards regulatory coherence [81], [82]. Currently, it is governed by rules addressing electricity generation, water use, and hydrogen production, storage, and distribution. Environmental requirements remain largely rooted in legislation originally intended for hydrogen use in the chemical industry. The main regulatory instruments, structured by their scope, are listed below.

#### Access to infrastructure

##### *Circular 8/2019 (CNMC)*

*Circular 8/2019 (CNMC)* currently regulates access and capacity allocation in the natural gas system. A proposed amendment seeks to:

- modernize access procedures and anti-hoarding provisions in light of current market conditions; and
- facilitate the integration of renewable and low-carbon gases by updating connection and capacity allocation rules.

*Royal Decree-Law 6/2022*

*Royal Decree-Law 6/2022* extends the natural gas regulatory framework to green hydrogen. This includes:

- applying existing legal provisions on transport, distribution, and supply to dedicated hydrogen networks; and
- imposing obligations on hydrogen network operators regarding administrative authorization, unbundling, and certification.

*Royal Decree-Law 8/2023*

*Royal Decree-Law 8/2023* authorizes natural gas transmission system operators to temporarily operate hydrogen backbone infrastructure, supporting early network development.

## Guarantees of origin

*Royal Decree 376/2022*

*Royal Decree 376/2022* defines renewable hydrogen as hydrogen produced from renewable sources and establishes conditions for obtaining guarantees of origin. Producers must:

- be registered in the national database for renewable gas facilities; and
- demonstrate that all electricity used in hydrogen production is certified via guarantees of origin.

*Order TED/1026/2022*

*Order TED/1026/2022* details the administrative procedure for managing the guarantees of origin system.

*Circular 1/2018 (CNMC)*

*Circular 1/2018 (CNMC)* specifies eligible renewable electricity sources for issuing guarantees of origin.

*Royal Decree 244/2019*

*Royal Decree 244/2019* requires producers using self-supplied renewable electricity to comply with proximity conditions.

*Royal Decree-Law 18/2022*

*Royal Decree-Law 18/2022* lifts restrictions on direct power lines between non-affiliated renewable producers and consumers, enabling decentralized production and bilateral power purchase agreements.

## Hydrogen storage

*Environmental Permitting*

A favourable environmental impact statement or report is required for:

- underground storage facilities; and
- above-ground facilities exceeding 50 hectares or 200,000 tonnes capacity.

*Royal Decree 840/2015*

*Royal Decree 840/2015* imposes additional safety and risk control measures when storage exceeds 5 tonnes, under hazardous substances regulation.

*Planning Requirements*

All storage facilities must obtain standard construction and operational permits in line with land-use and environmental law.

# A.5 Germany

## A.5.1 National strategies and policies

### The National Hydrogen Strategy: climate action for Germany's industrial sector

Germany's *National Hydrogen Strategy*, adopted in June 2020 [83], aims to support climate action, strengthen energy import diversification, and enhance energy security. It also seeks to drive innovation, create future-oriented jobs, and position German companies as global leaders in hydrogen technologies, particularly in electrolysis and fuel cells. The strategy is implemented through a flexible, result-driven governance framework, with the National Hydrogen Council playing a key advisory role since its first meeting in July 2020.

The strategy pursues the following objectives in particular:

- Promote climate-friendly hydrogen (especially green hydrogen) as a central part of the energy transition and decarbonization efforts.
- Develop regulatory frameworks to support market growth for hydrogen production and use, focusing on sectors difficult to decarbonize (e.g. heavy industry, aviation, shipping).
- Lower technology costs to stimulate domestic and international hydrogen markets.
- Boost German competitiveness by accelerating R&D and supporting exports of innovative hydrogen technologies.
- Ensure future hydrogen supply through domestic generation and international partnerships, including with renewable-rich developing countries.
- Support interim use of low-carbon hydrogen (e.g. blue and turquoise) to speed up market ramp-up, especially in key industrial sectors.

### Update of the National Hydrogen Strategy

In July 2023, the Federal Cabinet agreed on the *Update of the National Hydrogen Strategy* [84], amending and further developing the 2020 strategy to reflect new developments.

The *Update of the National Hydrogen Strategy* is pursuing the following target visions for 2030.

*Accelerated market ramp-up for hydrogen*

The market ramp-up of hydrogen, its derivatives and hydrogen utilization technologies will be significantly accelerated and the level of ambition along the entire value chain will be massively increased.

*Assurance of sufficient availability of hydrogen and its derivatives*

The goal for domestic electrolysis capacity in 2030 will be raised from 5 GW to at least 10 GW. The remaining need (45–50 TWh) will be covered by imports.

*Development of a high-performance hydrogen infrastructure*

By 2027/2028, the Important Projects of Common European Interest (IPCEI) Hydrogen funding will be used to construct a hydrogen network with over 1,800 km of adapted and newly built hydrogen pipelines in Germany, with over 4,500 km added in Europe (European hydrogen backbone). The expansion of a core network will connect all large generation, import and storage centres with the relevant consumers in Germany by 2032.

*Establishment of hydrogen use in the sectors*

By 2030, hydrogen and its derivatives will be used in industry, air, and naval transport. In the power sector, hydrogen will support energy security through hydrogen-ready gas plants and flexible electrolyzers. Legal changes now enable future hydrogen to use in centralized and decentralized heating systems.

*Germany to be lead provider of hydrogen technologies by 2030.*

Creation of suitable policy environment including coherent legal requirements at national, European and – insofar as possible – international level support the market ramp-up.

## The import strategy for hydrogen and hydrogen derivatives

The *Import strategy for hydrogen and hydrogen derivatives*, which were published by the Federal Government in July 2024 [85], supplements the *National Hydrogen Strategy* (NHS). The strategy aims to send clear signals to partner countries and companies about Germany's need and willingness to import hydrogen and hydrogen derivatives.

The strategy expects a need of 95–130 TWh of hydrogen and hydrogen derivatives by 2030, of which 50–70% must be imported. By 2045, the need is expected to increase to 360-500 TWh for hydrogen and 200 TWh for its derivatives.

The *Import strategy for hydrogen and hydrogen derivatives* sketches out the policy environment, measures and instruments along the entire value chain, which consist of the following.

*Diversification of the product range*

The *Import strategy for hydrogen and hydrogen derivatives* supports a broad mix of hydrogen and derivatives like ammonia and methanol.

*Diversification of the supply chains*

Germany builds partnerships worldwide and develops multiple European import corridors (e.g. North Sea, Baltic, South Europe).

*Transport infrastructure*

Hydrogen imports will rely on pipelines and ship terminals. Liquefied natural gas (LNG) terminals are being prepared for future hydrogen use. The core hydrogen network is planned for 2032.

*Boosting demand*

Incentives like carbon contracts for difference (CCfD), IPCEI hydrogen, and RED III quotas aim to create a stable domestic market and encourage investment.

*Stimulating the supply*

Germany backs global hydrogen projects via funding tools (e.g. $H_2$Global, European Hydrogen Bank, PtX Fund) and trade instruments (e.g. credit guarantees).

*Sustainability standards*

Germany commits to robust sustainability rules aligned with EU frameworks and works with partners to ensure compliance and improve standards.

## Core network: a basis for the hydrogen supply

The goal of the core network is to connect central hydrogen sites like industrial centres, storage areas, power plants and import corridors across Germany.

By 2032, just under 10,000 kilometres of new pipelines and of adapted natural gas pipelines are to be added to the length of the hydrogen core network. 60% of the network is already available as natural gas pipelines, which can be repurposed for this use. A further step of the plan is to gradually connect more manufacturing companies or power plants via additional pipelines.

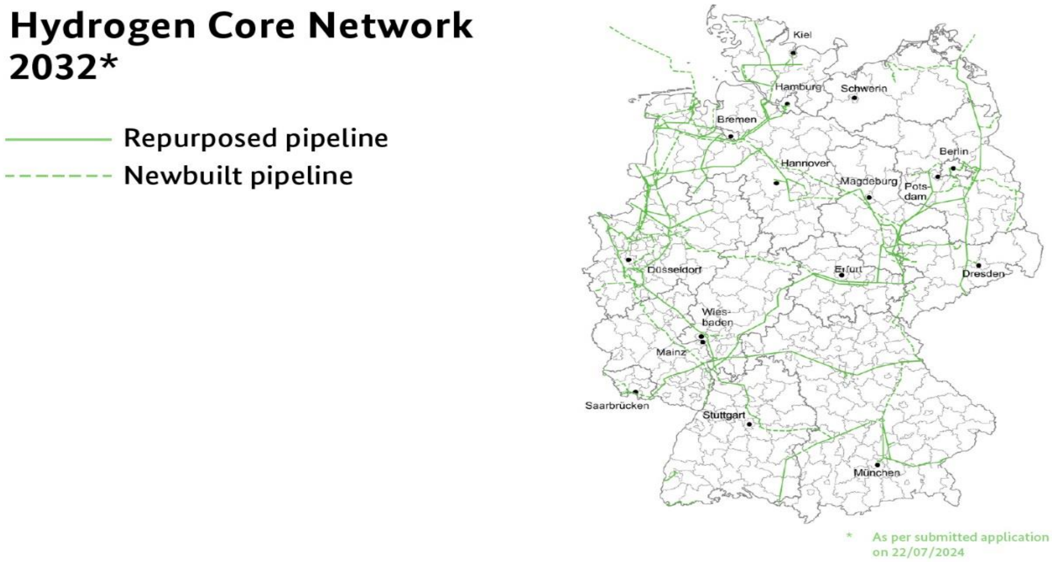



Figure 21. Hydrogen core network (as of July 2024). Source [85].

The expansion of the hydrogen network is to be financed through usage-based charges managed by the private sector. According to the federal government's model, these charges will be distributed over a long period – up to 2055 – using an amortization account to prevent high upfront costs. This approach helps balance early-stage demand and infrastructure availability.

Once hydrogen demand in Germany reaches a level that requires the majority of it to be imported, the network will be reconfigured to accommodate this and to enable pipeline-specific deliveries across German borders.

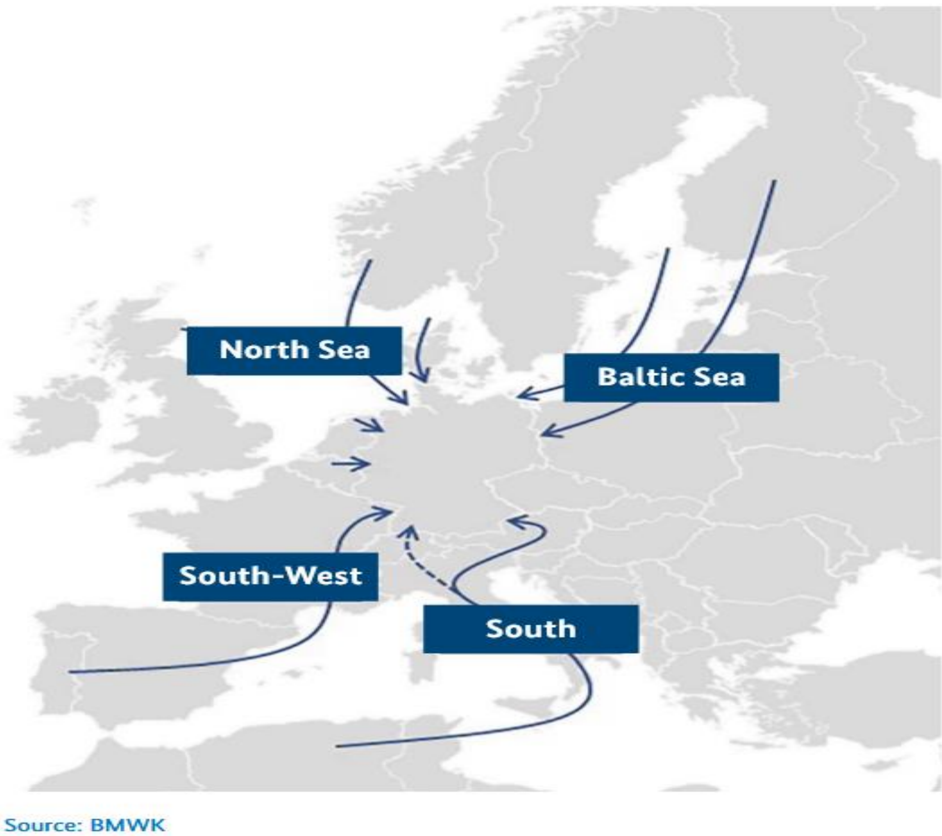


Figure 22. Schematic depiction of European import corridors (as currently envisaged; dotted line indicates prospective expansion) [85].

### Funding guideline for international hydrogen projects

To meet future demand, Germany will need to import clean hydrogen in addition to expanding domestic production. At the same time, the growth of the international hydrogen economy presents export opportunities, with German companies positioned to lead in hydrogen technologies.

In support of this, the Federal Ministry for Economic Affairs and Climate Action, together with the Federal Ministry of Education and Research, has introduced a funding guideline for international hydrogen projects. As part of the *National Hydrogen Strategy* and financed through the economic stimulus package, the guideline offers grants of up to €15 million to bridge financing gaps for investment and research projects that are not yet economically viable. The focus is on supporting the development of green hydrogen production, storage, transport, and integrated applications outside the EU and European Free Trade Association (EFTA) regions. This initiative promotes the global market uptake of clean hydrogen, facilitates the international deployment of German technologies, and prepares the ground for future hydrogen imports.

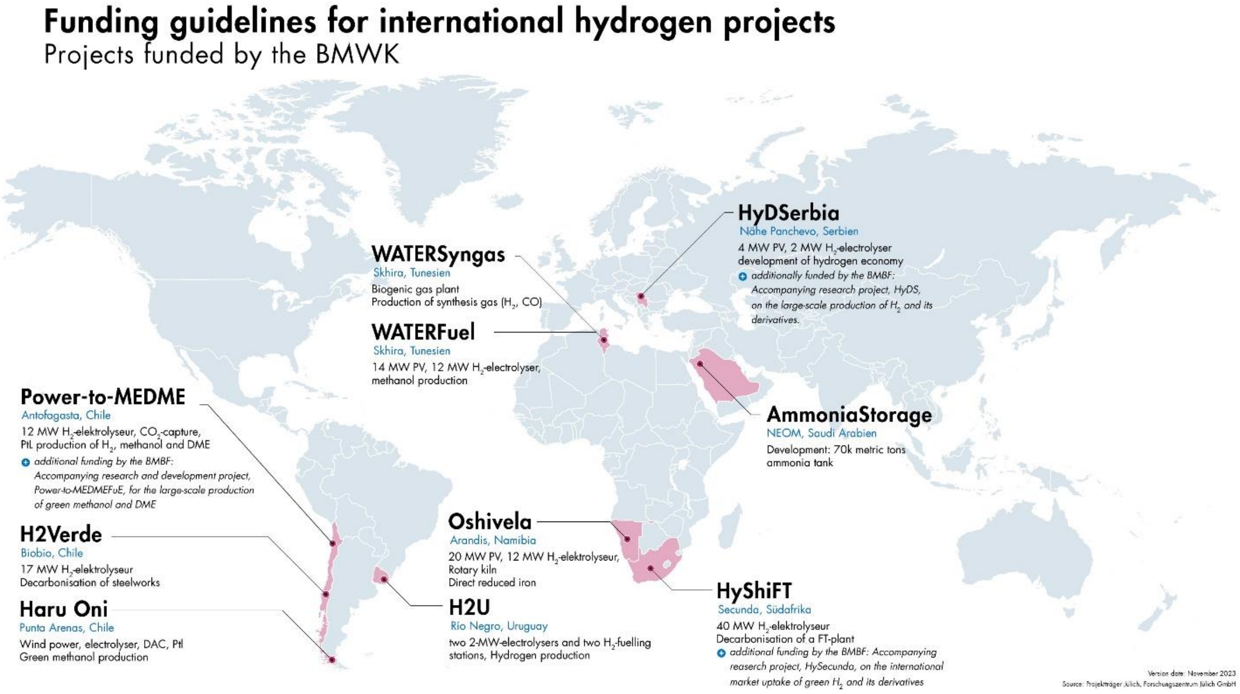



Figure 23. Founding guidelines for international hydrogen projects [85].

## *A.5.2 National regulations*

The following provides a brief overview of the legal acts governing the development of hydrogen networks in Germany.

### *The Electricity and Gas Supply Act*

*The Electricity and Gas Supply Act* (DE, Gesetz über die Elektrizitäts- und Gasversorgung, Energiewirtschaftsgesetz – EnWG) is a German law establishing the legal framework for the supply of electricity and gas. It aims to ensure a secure, affordable, consumer-friendly, efficient, and environmentally compatible energy supply, while also promoting effective competition and guaranteeing reliable and long-term operation of energy networks [86].

*The Ordinance on Costs and Fees for Access to Hydrogen Networks*

*The Ordinance on Costs and Fees for Access to Hydrogen Networks* (DVerordnung über die Kosten und Entgelte für den Zugang zu Wasserstoffnetzen (Wasserstoffnetzentgeltverordnung – WasserstoffNEV) is a German ordinance, effective since 1 December 2021, that sets out how costs and fees for accessing regulated hydrogen networks are determined. In particular, it establishes rules for cost assessment, tariff-setting, and ensures transparency and cost-based pricing for network access [87].

*The Hydrogen Acceleration Act*

*The Hydrogen Acceleration Act* (DE, Zum Wasserstoffbeschleunigungsgesetz: Wichtige Weichenstellung für den Wasserstoffhochlauf weiter verbessern) is a German legislative proposal aimed at expediting the development of hydrogen infrastructure by accelerating planning, approval, and construction processes across the entire hydrogen value chain – including production, storage, import, and related facilities – through legal reforms and digitalisation [88].

*The law on energy conservation and the use of renewable energies for heating and cooling in buildings*

*The law on energy conservation and the use of renewable energies for heating and cooling in buildings* (DE, Gesetz zur Einsparung von Energie und zur Nutzung erneuerbarer Energien zur Wärme- und Kälteerzeugung in Gebäuden), which came into effect on 1st November 2020, unifies Germany's existing energy-saving regulations into a single legal framework and sets mandatory energy-efficiency standards for both new and existing buildings while promoting the use of renewable energy for heating and cooling [89].

*Section 249a, Special Provisions for Projects for the Production or Storage of Hydrogen from Renewable Energies*

*Section 249a, Special Provisions for Projects for the Production or Storage of Hydrogen from Renewable Energies*, Baugesetzbuch (BauGB § 249a Sonderregelung für Vorhaben zur Herstellung oder Speicherung von Wasserstoff aus erneuerbaren Energien) introduces a special planning provision allowing projects for the production or storage of hydrogen to be granted privileged status – making them permissible outside formal zoning areas – provided they are spatially and functionally connected to existing renewable energy facilities, such as wind turbines (§ 35(1) No. 5 BauGB) or solar installations (§ 35(1) No. 8 b or No. 9 BauGB), and meet certain technical and size-related criteria [90].

*Act Amending the LNG Acceleration Act, the Energy Industry Act, and the Building Code*

*Act Amending the LNG Acceleration Act,* the *Energy Industry Act,* and the *Building Code,* (DE, Gesetz zur Änderung des LNG-Beschleunigungsgesetzes und zur Änderung des Energiewirtschaftsgesetzes und zur Änderung des Baugesetzbuchs), published in July 2023, streamlines the expansion of liquefied natural gas (LNG) infrastructure in Germany to enhance energy supply security – particularly in response to reduced reliance on Russian gas – by clarifying post-use repurposing of LNG sites for climate-neutral hydrogen and derivative operations and accelerating approval processes. It also adjusts the *Energy Industry Act* and the *Building Code* to support these developments, including provisions facilitating the installation and conversion of energy infrastructure while integrating decommissioning requirements and land-use flexibility [91].

## A.6 Norway

### A.6.1 National strategies and policies

Norway is committed to decarbonization process and is developing hydrogen energy projects for, maritime, transport and industrial sectors [92] in support of the total greenhouse gas emission reduction by at least 50% by 2030 [93].

## Main elements of the government's hydrogen strategy

The government has prioritized efforts in the areas in which Norway has a particular advantage, where Norway and Norwegian companies and technology communities can influence development, and where there are opportunities for increased value creation and green growth.

If hydrogen is to become a viable zero-emission alternative, both in Norway and globally, it must be safe and accessible, both technologically and financially. In many commercial applications, energy costs are important in terms of a company's global competitiveness. Based on the current costs of energy and emissions, the energy losses generated by producing hydrogen and the cost of storing it make the utilization of clean hydrogen less profitable compared with fossil energy sources or other low and zero-emission solutions. Hydrogen is currently not competitive in many of the areas of application that could be of interest.

Emissions pricing, through taxes and the emissions trading system, is designed to promote low-emission solutions. A more stringent emissions trading market, combined with the increase in the $CO_2$ tax announced by the government, will make emission-intensive solutions more expensive. In the Granavold political platform, it was announced that the government will increase the flat $CO_2$ tax by 5% every year for all sectors until 2025.

Demonstration and piloting of hydrogen and hydrogen-based solutions could lead to hydrogen being used as an energy carrier in new areas of application. Developing technology could affect the supply side, through reduced production costs, and the demand side, through new markets. Technology development and innovation from a value chain perspective could assist in drawing on potential synergies between industries. Therefore, the national PILOT-E scheme was developed.

The PILOT-E initiative contributes to developing and demonstrating energy-efficient and cost-efficient methods and value chains for the production, transport, storage and use of clean hydrogen, through among others, joint calls for proposals in the PILOT-E scheme. Specifically:

- The government will, through current policy instruments, continue to support the necessary technological developments. The authorities will monitor developments and adjust policy instruments if needed.
- The government will, in conjunction with the *Climate Plan for 2030*, evaluate policy instruments to promote the development and use of hydrogen in Norway.
- The government will continue to support research into, and the development and demonstration of hydrogen technologies through relevant schemes, with a focus on projects of a high scientific quality and potential for commercial development.

### *Production*

The most widespread methods of producing hydrogen are natural gas reforming and coal gasification. Global demand for hydrogen is today around 70 million tonnes [94]. Around 3% of global energy production is used to produce this volume. The bulk of hydrogen produced globally comes from natural gas (76%), followed by coal (23%). Only 1% from electrolysis of water. In Norway, electricity used to produce hydrogen through electrolysis is currently exempt from the consumer tax on electricity. This helps to reduce the cost level at which hydrogen becomes competitive compared with other energy carriers. In 2020, the consumer tax on electricity is 0.1613 NOK/kWh.

### *Consumption*

The energy content of hydrogen can either be utilized by converting hydrogen into electricity through fuel cells, or by producing energy or heat through combustion, in the same way as natural gas. Hydrogen can also replace fossil fuel input factors in industrial processes. Continued research and development is needed in order to improve the technology and make it cheaper.

The number of projects for hydrogen production through electrolysis is increasing [95] and creates a considerable growing load for the national power grid.

## A.6.2 National regulations

Norway has a *national hydrogen strategy* [96] focused on leveraging its resources to become a leading producer and exporter of low-emission hydrogen, particularly for maritime and industrial sectors, with a technology-neutral approach that supports both green and blue hydrogen. Regulations involve general construction permits and sectoral rules under the *Fire and Explosion Prevention Act*, alongside alignment with EU directives for market access and support for low-emission gas uptake. The regulatory landscape is developing, with Norway actively promoting hydrogen development through funding, research, and pilot projects like hydrogen-powered ferries and trucks.

### Key aspects of Norway's hydrogen strategy

#### *Low-Emission Focus*

Norway's strategy prioritizes hydrogen produced with low or zero emissions, utilizing natural gas with carbon capture and storage (blue hydrogen) or renewable electricity (green hydrogen).

#### *Targeted Sectors*

The primary focus is on hard-to-abate sectors, especially maritime transport and energy-intensive industries, where hydrogen can provide long-range, short refuelling options.

#### *Technology Neutrality*

Unlike some other European countries, Norway adopts a technology-neutral stance, supporting various pathways to low-emission hydrogen.

#### *Value Chain Development*

The government aims to foster integrated hydrogen value chains, encompassing production, distribution, and use, to build national expertise and drive exports.

#### *Research and Development*

Significant focus is placed on R&D to improve hydrogen production efficiency and develop new solutions, supported by centres like the FME HYDROGENi [97] and ENOVA [98].

### Relevant Regulations

#### *Construction Permits*

New hydrogen projects may require construction permits under the national *Planning and Building Act* [99].

#### *Fire and Explosion Prevention Act*

The construction and operation of hydrogen plants are subject to strict regulations under this act, overseen by the Norwegian Directorate for Civil Protection (DSB).

#### *Energy Act*

Facilities in connection with a hydrogen plant may require a licence from the Norwegian Water Resources and Energy Directorate (NVE) under the *Energy Act.*

#### *EU-Aligned Regulations*

Norway's hydrogen market is increasingly influenced by EU regulations, such as the *Internal Gas Market Regulation*, which mandates non-discriminatory market access to hydrogen networks and provides discounts for low-emission gases to stimulate uptake.

### Regulatory Development and Future Outlook

Norway has signalled a high level of ambition for hydrogen, which plays a crucial role in its climate goals.

State aid and funding are being directed towards low-carbon hydrogen projects, particularly those considered Important Projects of Common Interest (IPCEI) under EU guidelines.

The regulatory framework is still evolving, with ongoing efforts to establish clear rules and frameworks to facilitate the widespread adoption of hydrogen.

# A.7 Switzerland

## A.7.1 National strategies and policies

Swiss policy makers have developed a hydrogen strategy [100] and assessed different option to enhance a national hydrogen economy, which is the prerequisite for an efficient hydrogen market. The findings summarized below have a Swiss perspective but generalize to other countries.

The Swiss hydrogen market should be closely coupled with Europe, but the concrete rollout is not specified yet.

A variety of subsidy mechanisms along the hydrogen supply chain have been identified to ramp up the hydrogen economy [101].

### Supply side

Investment or operating cost subsidies for hydrogen production. The potential supply-side subsidy instruments have been assessed as follows.

*Subsidies on operating costs*

- Generally high subsidy costs.
- Possible scattering losses i.e. overpromotion of applications with a high willingness to pay
- Subsidy of inefficient hydrogen applications.
- Possibly production in hours with a relatively high electricity price, leading to stress on the electricity sector.
- Part of the subsidies may be used outside of Switzerland.

*Flexible grid tariffs*

- Incentivizes grid-friendly dispatch of electrolyzers.
- Requires adjustment of current tariff-design.

*Certificates for green hydrogen*

- Useful to activate customers willing to purchase green hydrogen.
- Prerequisite for the demand-side promotion of hydrogen.

*Investment support*

- Can mitigate immature market with unclear market dynamics.
- No negative impact on electricity grid stress.
- Payback options are possible to mitigate overpayments possible with rising hydrogen prices.

### Demand side

Investment or operating cost subsidies for consumption facilities, quotas for renewable energy sources or bans on fossil fuels. Furthermore, taxes and $CO_2$ prices increase the demand for hydrogen by burdening the final consumption of fossil fuels and relieving the burden on renewable energy sources.

Hybrid (or combined) support mechanisms, such as certificate systems for renewable energy sources or double auctions for supply contracts

The industry has pointed out that larger projects that are not pilot or demonstration projects also need to be promoted to market maturity.

### Swiss Hydrogen economy and current projects

Switzerland has developed a national hydrogen strategy, outline hydrogens roles and perspectives in the context of the Swiss energy transition [100].

The key points are seen as guidance for the energy industry and include the following:

- Hydrogen contributes to achieving the net-zero target, that Switzerland wants to achieve by 2050. Furthermore, hydrogen will contribute to the security of supply as a means for diversification of the energy sources.
- Switzerland aims to focus on green hydrogen from $CO_2$-neutral production from electrolyzers.
- Hydrogen and PtX derivatives are used where it makes economic and ecological sense. Hydrogen should primarily be used as a high-quality energy source primarily in the industry (high-temperature process heat) and to some extent to cover peak loads in combined heat and power (CHP) plants and thermal grids, in reserve power plants and to some extent in transportation (aviation, shipping and heavy goods vehicles).
- The Swiss hydrogen market should be closely coupled with Europe, but the concrete rollout is not specified yet.
- The industry has pointed out that larger projects that are not pilot or demonstration projects also need to be promoted to market maturity. So far (2025) this has happened only on a limited scope with projects under development:
  - A 2 MW production plant is under construction to produce 260 t of Hydrogen annually to be used for local shipping.
  - A 10 MW production plant at a former substation building is planned to produce 1200 t of Hydrogen annually to be transported via a short pipeline to a local gas station. A similar project of 15 MW is planned near a river power plant, with a pipeline to a local gas station [102].
- The connection of Switzerland to the European hydrogen backbone is uncertain, but essential from the Swiss point of view [103]. Potential connection points are at the border to Italy, along the current north–south transit pipeline for natural gas, as well as at the eastern border to Austria, an area with important chemical industry and a main consumer of hydrogen in Switzerland.

## *A.7.2 National regulations*

Swiss national regulation for hydrogen is not fully in line with the European regulation. In contrast to Europe’s mandatory frameworks, Switzerland currently aims at a market-driven and incentive-based approach [104].

- There is no comprehensive Swiss federal hydrogen network law, enforcing the unbundling of hydrogen production and transport.
- With the national hydrogen strategy, Switzerland is moving towards alignment with EU standards regarding the technical classification of hydrogen to facilitate cross-border trade but currently has not strict definitions for production pathways.
- There are no hard mandatory sectoral quotas for hydrogen use, but only incentives, with a focus on heavy-duty transport.
- Switzerland is working to align itself with EU-regulation to ensure the option to connect to the European hydrogen backbone and join the European Network of Network Operators for Hydrogen (ENNOH). Essential steps include:
  - completing a formal energy agreement with the EU;

- Implementing unbundling rules; and
- adopting the EU's certification system for hydrogen types.