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Hydrogen's impact on grids

Impact of hydrogen integration on power grids and energy systems

ETIP SNET

European Technology and Innovation Platform
Smart Networks for Energy Transition

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1.1 Introduction

The EU is undergoing an energy transformation towards a climate-neutral continent by 2050. It has set targets to progressively reduce greenhouse gas emissions towards clean energy to reach this goal and deliver on the EU's Paris Agreement commitments. These high-level climate targets will require structural changes in various sectors and impact society and the economy. Decarbonisation is reached mainly through electrifying various sectors (currently relying on fossil fuels) stemming from variable Renewable Energy Sources (vRES) and low-emission sources complemented by low-carbon gases.

Energy system integration refers to planning and operating the energy systems "as a whole" across multiple energy carriers, infrastructures, and consumer sectors. It creates more robust links between them to deliver low-carbon, reliable and resource-efficient energy services at the least possible cost for society.[3] It should aim at optimising the whole energy system rather than decarbonising and making separate efficiency gains in each sector independently.

As for the future, 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 carriers - electricity, heat, cold, 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.

The discussion on hydrogen as an energy carrier for the EU's decarbonisation intensified in 2020. In line with recent EU strategies on innovative sector integration and hydrogen, there is a consensus that hydrogen will play an essential role in the future. Thus, ETIP-SNET intends to understand the benefits and challenges of the hydrogen topic as a direct impact on power system operation and planning and, more broadly, in an optimised whole energy system perspective. In particular, this paper addresses the following High-Level Use Cases (HLUC) that are defined in the ETIP-SNET R&I Roadmap 2022-2031: HLUC1 "Optimal Cross Sector Integration and Grid Scale Storage", HLUC4 "Massive RES Penetration into the Transmission and Distribution Grid", HLUC5 "One-Stop Shop and Digital Technologies for Market Participation of Consumers (Citizens) at the Centre" and HLUC9 "Flexibility Provision by Buildings, Districts and Industrial Processes". This paper presents key findings, principles, and key messages for addressing R&D efforts and market/regulation changes needed.

As stated in the 2022 Joint Clean Hydrogen Partnership and Mission Innovation report, Europe´s ambition and position aim at significantly increasing Hydrogen valleys in Europe "Europe is very much a frontrunner, with the European Commission increasing political targets for hydrogen and introducing policies and regulation to support market development: After the EU Green Deal and the "Fit-for-55" package, the "REPower EU" plan aims for a speed-up and scale-up of renewable energy build-out and production and usage of clean hydrogen, amongst other objectives, calling for doubling the number of Hydrogen Valleys in Europe."

The paper's main body specifically addresses the impact on the power grids and the energy system. In Appendix 1 a comprehensive overview is reported on hydrogen's role in decarbonisation, demand, production and supply chain, including storage and transport options, while Appendix 2 reports on a use case in MV / LV.

1.2 Overarching issues related to power-to-hydrogen developments in the context of grids integration

Electrolysers shall be realised as industrial investments primarily by private bodies, having secured their business case based on purchases of hydrogen (or its derivatives) from off-takers. They will then submit a request for connection to the grid in a location and with characteristics according to their needs and constraints. However, in the perspective of large-scale integration of electrolysers (e.g., in a range of hundreds of GW) in Europe, their impact, both on local grid and the broader energy system, is not treatable as a mere new load, requiring just a connection solution. It is instead a question of system architecture, which must be addressed since the start as a coordinated energy system development among hydrogen operators, gas operators and power grid operators, and, of course, the private investors making the large investments in electrolysers.

In this regard, some key overarching issues arise:

Issue #1) Relationship between supply driven and demand driven aspects

On one side, one can consider building electrolysers for exploiting excess RES, and, on the other side, one can develop additional RES for exploiting green H2 decarbonisation capacity and system flexibility. Both approaches have to match the final users’ demand evolution, therefore a virtuous loop between supply needs and demand needs has to be set-up, under a coordinated holistic development of whole energy system.

Issue #2) Use cases and their impact on grids

An analysis of possible location and use cases shows that P2H2 projects must be assessed with an end-to-end approach, in economic terms, energetic terms, decarbonisation effect and cost-effectiveness vs other alternative solutions to obtain the same decarbonisation target. 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.

Issue #3) Flexibility from electrolysers and from H2 ecosystem

Large scale electrolysers can offer short term flexibility and grid services, dependent on technologies and on H2 off-take agreements, as well as long term flexibility, adequacy resource and resilience, dependent on the specific H2 ecosystem: final uses, logistics, storage options, market(s) for the commodity.

Issue #4) Impact on scenario definition and system planning methodologies

H2 projects are still uncertain (in time plan, number, size, locations, grid interaction, operation mode), and this poses dilemmas on how to include them in the joint electricity and gas scenarios (which have recently already been requested to be elaborated jointly by electricity and gas operators) and how to assess them from system perspective.

2. Hydrogen operational economics and use cases

2.1 Green Hydrogen: cost drivers, operation modes and topology

The most important operational cost factors of H2 produced by electrolysers are electricity price and load factor (see Fig. 1 below, referred to Alkaline technology, for a given Capex).

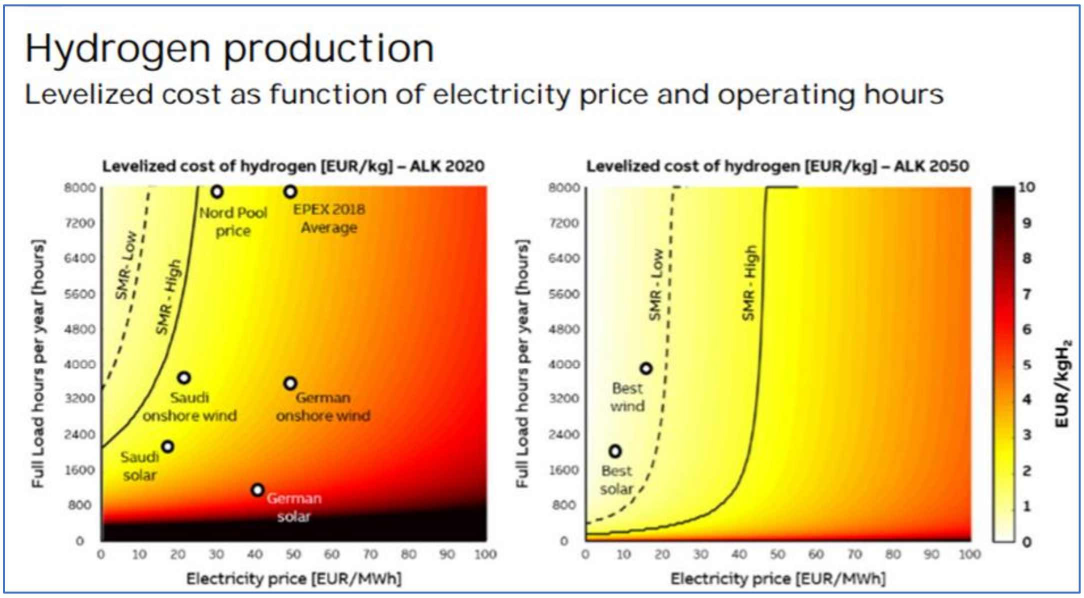


Figure 1. Levelised cost of Hydrogen production (Source: ABB H2 study, 2020)

Although costs in this field are varying in a very dynamic fashion, it is important to consider consistent benchmarks (example Fig. 2)

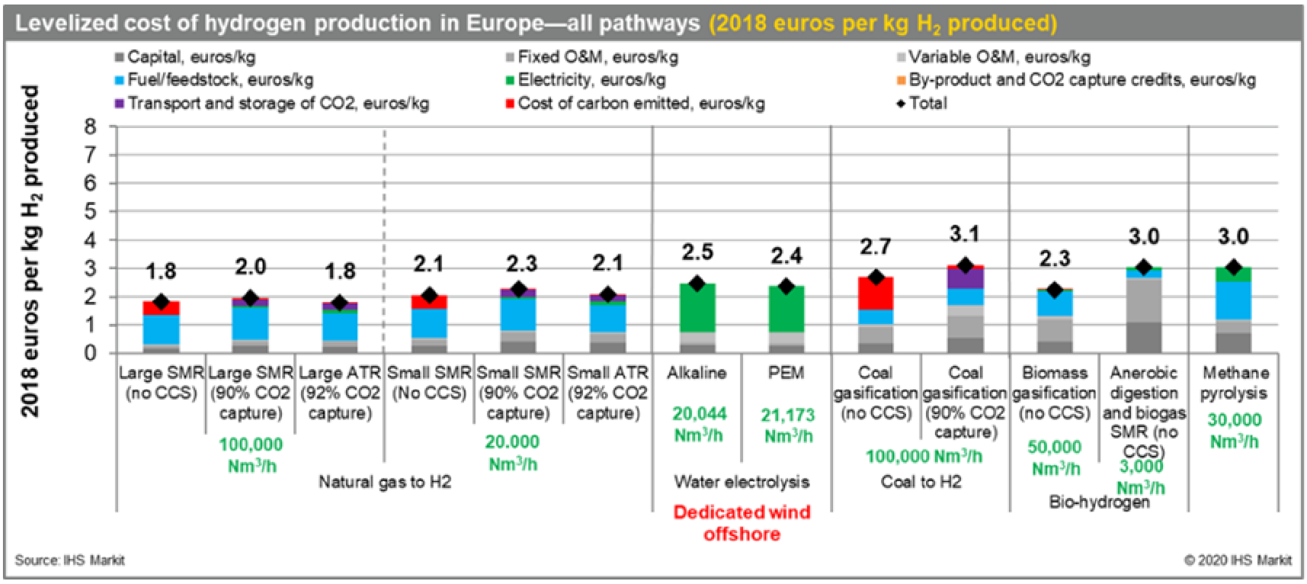


Figure 2. Benchmark of hydrogen production cost depending on production technology & process (Source: HIS Market)

There is a clear minimum threshold of load factor below which economic viability is not possible. This threshold will be smoothened by future lower CAPEX, but will not disappear. From this point of view, the following operational modes can be envisaged, under the common assumption that H2 is valuable to the energy-climate transition only if it is effectively contributing to decarbonisation:

- Spot operation mode
- Baseload operation mode
- Market-based operation mode

- Dedicated operation mode (for a specific RES installation).

The operational mode, together witthe topological localisation within the energy system, determines the grid impact of large electrolysers (Figure 2).

2.1.1 Spot operation mode (market price driven)

For minimising electricity price, it could be purchased on the spot when market prices are very low, or zero (even negative in some pool markets) and/or using energy which would otherwise be curtailed (equivalent to a zero price or negative price corresponding to the payment due to the generator, in places where this is provided for by applicable regulation). Except for curtailed RES, in order to have green H2 (or any case maximising the % of green H2 produced) a certification procedure must be in place, like Guarantee of Origin (GO). Since low electricity spot prices typically correspond to a very high RES generation (characterised by zero variable cost), the availability of sufficient green electricity should not be an issue, the question is only to properly certify it.

This operation mode is very efficient for the whole system, but is not convenient for the electrolyser owner, because the load factor is unpredictable and overall quite low (at least for the short/mid-term future). Moreover, it is necessary that the H2 off-take be very flexible, for example if there would be a liquid market for H2 and/or a large H2 on site storage associated; such storage would add its Capex & Opex to the business plan. Instead of H2, the off-take / storage could be for a synthetic fuel or chemical derived from H2, again adding conversion Capex & Opex.

If a deeper analysis (market- and location-specific) shows that the benefits to the system are worthwhile, a specific revenue stream could be added, which however should compete with other demand flexibility means.

Moreover, plant efficiency, durability and performances are negatively affected by a highly variable operational capacity profile.

In conclusion, this operation mode could come in a more mature period and/or in limited niche use-cases, also because a large deployment of this operation mode would smoothen/diminish the electricity price differentials which are at the base of its economic rationale.

2.1.2 Base load operation mode

It is the opposite concept of spot operation, i.e. maximising the load factor. This is particularly relevant for high Capex, i.e in the initial stage of electrolysers deployment, and requires a long term green electricity purchase contract at lowest possible prices and with flat profile availability. In order to attain a decarbonisation effect, this CO2-free electricity should be additional to existing generation. Nuclear energy (normally operated as baseload) could be a good match in terms of generation profile, but not as additional capacity since in Europe no new plants are envisaged. However, a compromise could be to contract the existing capacity as dedicated to H2 for the remaining life-time of existing plants, so allowing the time needed for additional RES and the whole H2 economy to kick-start. Those hydro power plants with year-round stable capacity (ample basin and limited seasonality inflows) could also be a good match for base load profile, but they are typically already committed to load-follow service (nowadays residual load), thanks to their very good dynamic performances, so probably an overall assessment would show them not to be suitable for feeding electrolysers.

Using 100% variable RES, which is the final goal, in particular new, purpose-built wind and solar plants cannot by itself ensure a sufficient load factor and will require commercial agreements for procuring the remaining supply of green electricity through emission related markets (GO, green certificates, etc.), but it will be more difficult to achieve if a 24/7 requirement shall be in place.

Off-take contracting is simpler and would ideally be in terms of PPAs, with large consumers of H2, like the present industrial sectors (refineries, chemicals) and new ones to be decarbonised (iron&steel, high temperature industrial processes, transport).

The economic viability depends on the electricity price contracted, and on the economics of subsequent use of H2, in particular of transport if needed.

In conclusion, this operation mode seems suitable for initial deployment of the H2 supply chain, but it shall need subsidies to overcome the cost differential vs black/grey hydrogen; such subsidies should be shaped in a way to at least compensate the CO2 emission reductions, and (if CO2 European market price will continue to be too low) include incentives for pilot projects and H2 industrial chain set-up.

2.1.3 Market-based operation mode (user demand driven)

In between the two previous modes, many combinations are possible in real cases; for example, dedicating a portion of the capacity to flat long-term off-takers, a portion to short term and/or programmable off-takers (final consumers or traders), a portion to spot sales.

On top of the production program, spare capacity can be used to provide system services to the power grid, exploiting all flexibilities inherent in the plant (variable load, local storage, off-taking flexibilities, pipeline delivery) and those commercially agreed with the off-takers. These system services, spanning from short term flexibility for the grid (ramping, frequency support, etc.) to long term modulation at energy system level, should be properly regulated and evaluated to complement the business plan, while at the same time benefitting the wider system in a cost-efficient way.

The issues are the same already analysed (in 2.1.1 and 2.1.2), and custom-tailored solutions are possible; indeed, especially at this early stage for the H2 economy, each project should be assessed in an end-to-end approach, considering the whole chain (supply-logistic-final use), particularly the externalities, in primis the net impact on CO2 emission, through appropriate Guarantee of Origin mechanisms, and the total net benefits for the final system user.

In conclusion, market operating mode is versatile but seems suitable when an H2 market and infrastructures will be in place.

2.1.4 Dedicated operation mode

To ensure 100% green H2 production, an electrolyser can be built directly connected to a large RES plant with high load factor; solar PV, with load factor capped to 25% is the least viable, while wind, especially off-shore, with up to 50% load factor, is the most viable. If the RES plant is located far from strong nodes of the power grid (and having spare acceptance capacity), like off-shore in North Sea, H2 also solves the power evacuation issue.

In order to increase the electrolyser load factor, a mixed solution is to dimension it for only part of the RES production; however:

- for PV, this does not increase the load factor, which is capped by sun daylight cycle
- for off-shore PV, this would mean to build electric connection on top of the electrolyser
- for on-shore wind, this changes the status of electrolyser from off-grid to grid-connected.

A dedicated operation mode could in theory be applied also to programmable RES, however:

- biogas/biofuels are themselves CO2-free energy vectors, indeed they compete with electrolysers-based synfuel production
- geothermal and hydro are well-suitable, with some potential still to be exploited (e.g., Iceland), but problematic due to low energy density, i.e., low power capacity
- nuclear could be an option, but no new plants are foreseen in Europe
- marine energy (in embryonal stage) has low power production density for filling a concentrated plant like electrolyser.

In conclusion, dedicated operation mode seems possible, in Europe, only for large off-shore wind in North Sea, where it solves both the load factor and the evacuation issues.

2.1.5 Taxonomy of operational modes

According to the impact on the power system operation, the previous cases can be summarised in Fig. 3; it is also very relevant if storage elements are present in the surrounding infrastructure ecosystem, either on electric side or on hydrogen side: tanks, pipelines, caverns, consumer tanks, etc.. Indeed, this is creating a buffer which de-couples electricity input from hydrogen output, making possible a flexible operation of the electrolysers, benefitting the system while keeping its contractual obligations and so ensuring its business case.

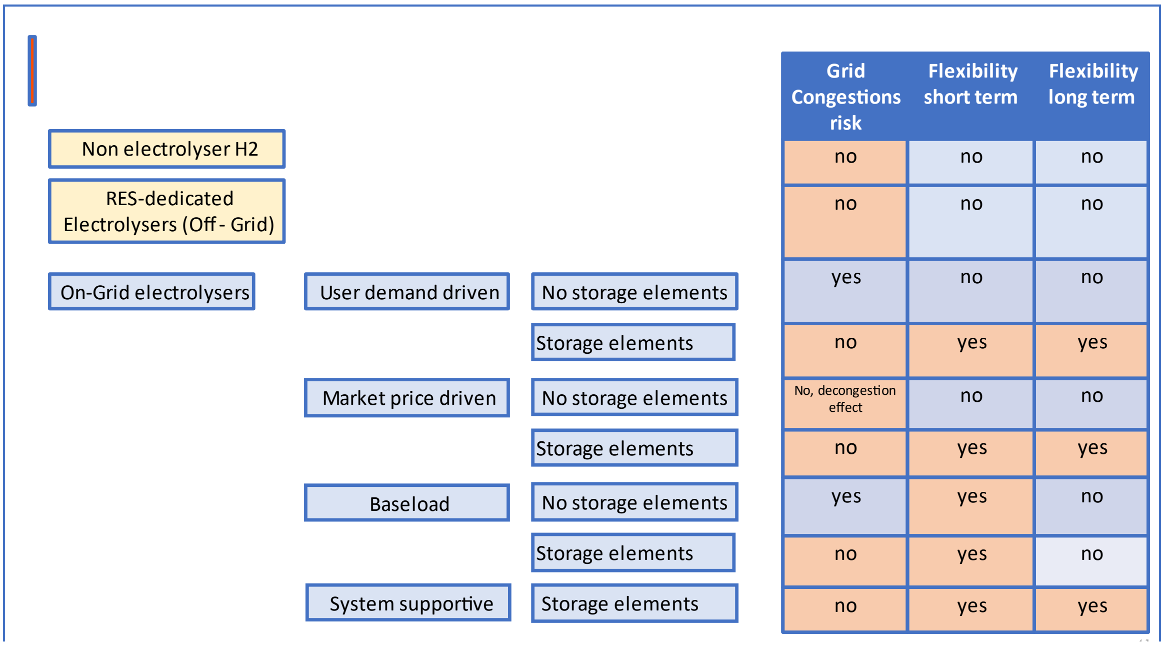


Figure 3. Taxonomy of electrolysers operational modes (grid impact perspective)

2.2 Electrolysers location and use cases

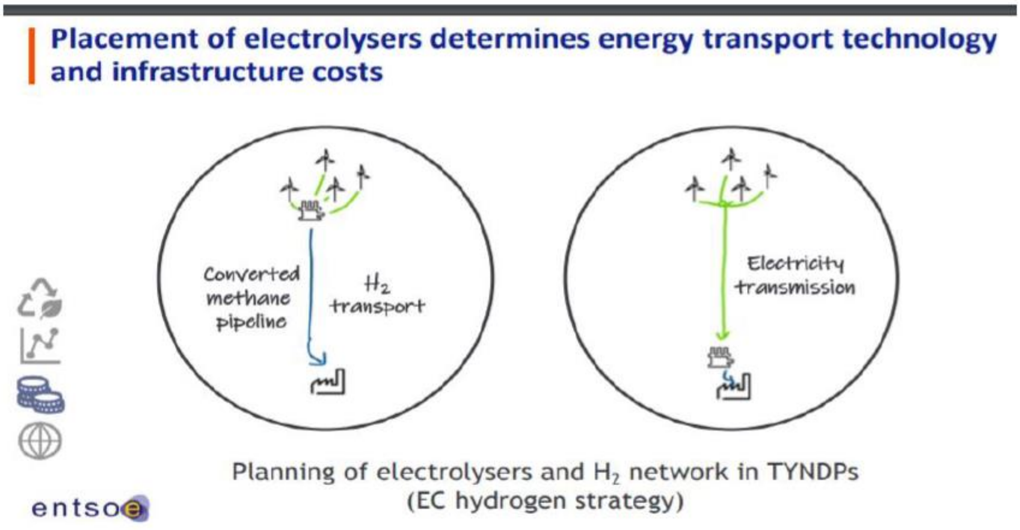
Location of electrolyser can be:

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

H2 physical destination can be:

- H2 consumed on its production site
- H2 transported to final consumer/storage
- H2 injected in a pipeline system gas grid
- destination has also a commercial dimension: sold to final user, sold to a trader, sold on a commodity market.

Use cases configurations are the viable configuration of electricity source, electrolysers location and H2 destination. Except the on-site use of hydrogen, this depends substantially on the transport options and on the conditions of the infrastructures: exisiting, to be repurposed, to be built (Fig 4 & Table 1).The most relevant options are briefly analysed in the following sections, **from the perspective of their impact on electricity grids.**



	Morphology	
Distance	**Overland**	**Sea traits**
Short	H2 valleys	H2 pipeline or electric cable
Mid-long (country / region)	H2 pipeline or OHL electric line	H2 pipeline or electric cable
Very long (inter-continents)	H2 pipelines	H2 ships

Figure 4 & Table 1. Localisation of large electrolysers and transport options including morphology by distance matrix for hydrogen transport

2.2.1 On-site production and use

Until today, H2 has long been a feedstock of oil refinery and petrochemical processes, with production on same site mainly through Steam Reforming of Methane (SMR), a process integrated with the refining ones; this is labelled black (or grey) H2, with high CO2 emissions and no need of logistic. There is little trading nor transport of H2, therefore it is not a market commodity and regulation deals only about safety.

The same applies to most large industrial H2 uses, which unlikely have possibility to build on same site a large RES plant and a dedicated electrolyser suitable in size and modulation to match the H2 off-take needs. The opposite might be feasible, i.e. to build a new H2-intensive industrial plant plus its electrolyser next to a large (existing or new) RES facility, but these are only limited cases.

For smaller scale industrial H2 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 electrolysers, in the order of a few 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 decarbonisation are taking the approach of, first, transitioning a fraction of their operations and only then start to gradually scaling up. In this intermediate scale, on-site production of medium-small H2 amounts is a real possibility, whereas it might have to be brought in from elsewhere in the future as demand grows. Furthermore, on-site production can also 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 commonly employed in such projects (wind and solar), there are other systems that enable the production of large quantities of H2 in relatively small areas – production of hydrogen from biomass.

2.2.2 Off-grid electrolysers

Large and remote RES plants can convert their generation into H2 and transport it (via ships or pipelines) to consumption areas, as an alternative to build new power lines, thus avoiding to impact on electric grids; in Europe, the most relevant case is with off-shore wind farms. The viability of off-grid electrolysers depends on the economic comparison (see previous section about load factor threshold), but also on the destination of H2:

- best business case is when H2 can reach directly the final H2 users
- intermediate business case is when H2 reaches an entry point of an H2 grid/storage system
- worst business case is if H2 is reconverted to electricity upon reaching a meshed electricity grid.

Only the latter case impacts on the electricity grid, in terms of new Gas-to-Power plants, but they will probably be a minority of cases, because reconversion means a loss of energetic efficiency.

2.2.3 Grid connected electrolysers

From previous considerations, it is likely that the majority of electrolysers will be of grid-connected type, even if located next to H2 consumption center or next to RES generation plant. This is both for 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 H2 (power grid services, H2 market arbitrage and flexibility serices provision etc.). Therefore, when this technology will be deployed and upscaled to the GW level, the electrolysers 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 electrolysers, 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.

2.2.4 Geo-electrical specificities considerations

The analysis of location options and use cases shows that, especially in first stage of development, P2H projects must be assessed with an end-to-end approach, in economic terms, energetic terms, decarbonisation effect and cost-effectiveness vs other alternative solutions. Focusing only on a piece of the supply chain (for example one electrolyser plant per se) falls short of providing conclusion on its system impact and viability. Supporting or even incentivising a stand-alone part of the supply chain would be short-sighted and potentially far from optimal choice.

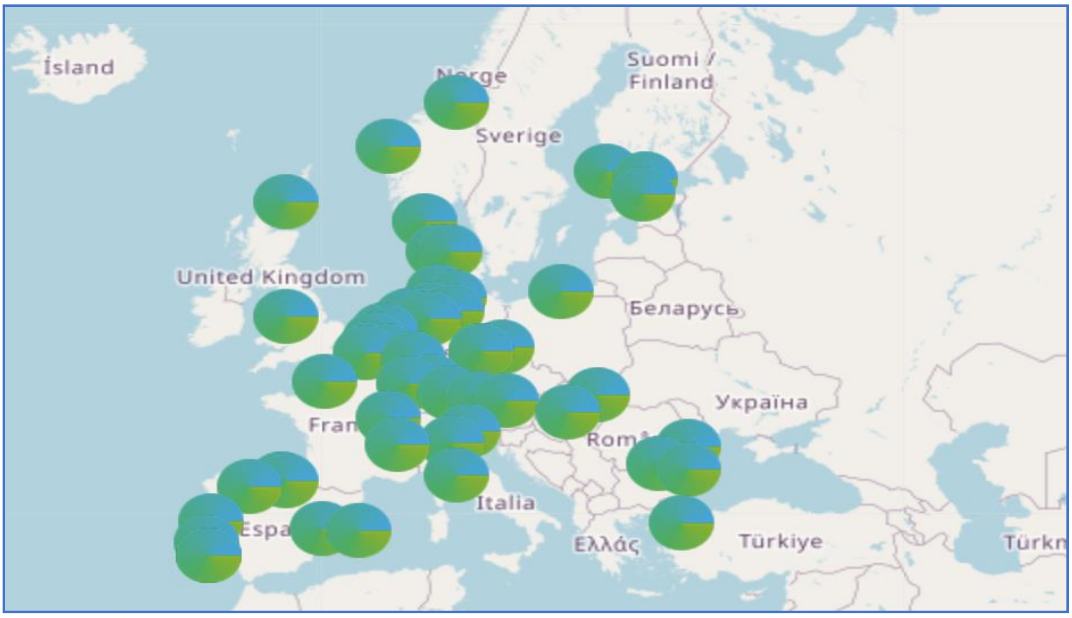
Each project and each geography/industrial configuration needs a specific analysis, taking in due consideration RES characteristics, transport and storage options (existing/prospected infrastructures), H2 destination features, as well as externalities (positive and negative) on adjacent sectors. This analysis, coupled with applicable energy policies in place, determines some areas as export-oriented, some as import-oriented, others areas as local cluster-oriented ("Hydrogen Valleys"), others as not suitable for H2 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.

2.2.5 Hydrogen Valleys

In order to organise ecosystems and foster value chains enablement the concept of Hydrogen Valleys evolved. These valleys are expected to become an important building block facilitating production, importing and exporting, distribution, transporting, and regional use of clean hydrogen inEurope and beyond. Other geographies are following the trend and leveraging best practices to and developing hydrogen hubs, clusters, ecosystems and other components comprised of aggregation and networks of various hydrogen users, shared infrastructure components and joint supply sources.

From the grid impact stand point it is important to take the impact of Hydrogen valleys into consideration and the related evolving models, so that impact can be analysed and taken into the grid planning considerations.



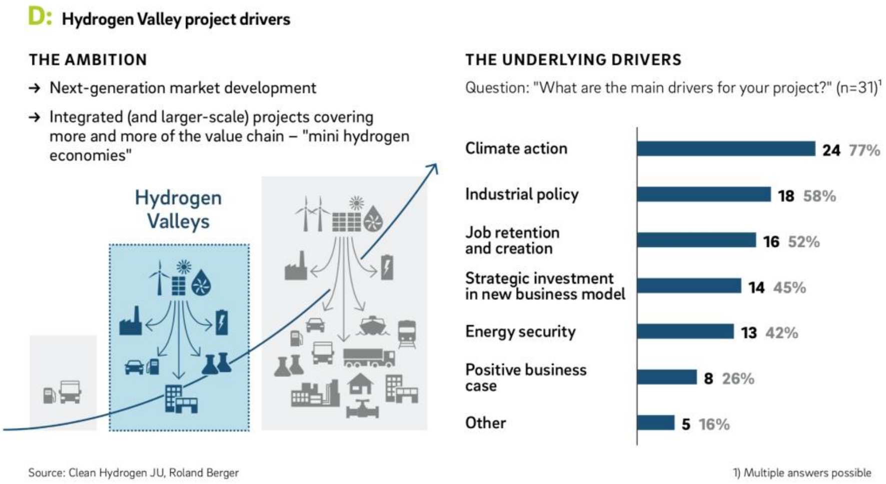


Figure 5 & 6. Map of Hydrogen Valleys and the project drivers

Recent report on Hydrogen Valleys states there are 81 Valleys across the world and 67% of the Valleys are located in Europe.[1]

A Hydrogen value chain must be developed from scratch both on supply side and on demand side, as well as the logistics infrastructure linking supply and demand. To start with simpler, less capex-demanding cases, probably the first investments will be realised in industrial conglomerates with clear and trustable off-takers and possibilities to build/reconvert industrial facilities to produce blue/green hydrogen, the so-called hydrogen valleys. This will save the need to build 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

[1] H2V Project : https://h2v.eu/hydrogen-valleys

logistics; they can be a first step for developing construction and operational experiences, as well as investments ecosystem and trading arrangements.

To analyse the impact of the EU Hydrogen Valleys on the electric grids, both the demand for electricity from hydrogen production and the capacity of the grid within the region to meet this demand needs to be taken into consideration.

Further analysis needs to be done, including flexibility potential from these production sites in order to estimate the total electricity demand from the hydrogen valleys.

There is a very heterogeneous situation with the capacity of the electric grid in the areas surrounding the hydrogen valleys, the existing infrastructure, including power plants, transmission lines, and substations. If a system of system approach is undertaken then the assess of the impact of the increased demand on the electric grid on regional and intraregional level should be done (may include analysing voltage and frequency stability, power flow, and other aspects of grid operation and the impact on other electricity consumers in the area).

It is necessary to have a good source of potential solutions to address any issues identified in the analysis. This may involve upgrading the electric grid infrastructure, increasing the use of renewable energy sources, implementing demand-side management programs, or other measures.
By creating a structured methodology for assessment and further detailed analysis, it will be possible to gain a better understanding of the impact of hydrogen valleys on the electric grid and identify ways to address any challenges that arise.

3. Optimisation and coordination of Hydrogen in the Energy System

3.1 Holistic approach and system development planning

Hydrogen will play an increasing role in the future to decarbonise the EU economy. Not all, but some of this hydrogen will be produced in the EU by electrolysers connected to the electricity grid. Thus, it is important to plan and realise the future system, including the electrolysers and the infrastructure, in a cost-efficient way. Therefore, the European and national planning processes for the electricity infrastructure have to integrate a multi-sectorial approach, both for natural gas and for hydrogen, with a one system view.

As indicated in the recent "Hydrogen and Gas markets decarbonisation package", December 2021, the new package proposal aims to ensure a more integrated network planning between electricity, gas, and hydrogen networks to make the development of energy infrastructure more cost-effective and allow transnational exchanges of information on transmission systems usage.

Such a multi-sectorial integrated planning would allow to optimally plan the infrastructure so that e.g. the electrolysers are well placed without causing potential bottlenecks and congestions in the grid, the energy is transported via electricity and hydrogen infrastructure cost-efficiently. The alternatives would be proven in a cost-benefit-analysis to demonstrate their benefits for the society.

In the context of the smart sector integration strategy, the coordinated development (and operation) of infrastructures of the relevant sectors will be one of the most important results to be delivered by the Associations of energy System Operators (ENTSO-E, ENTSO-G, E.DSO, EU DSO Entity). Some of these aspects are already implemented in the TYNDP, namely the joint scenario definition between ENTSO-E and ENTSO-G, some are being implemented at the moment (coordinated modelling of electricity and gas grids through an interlink model) and some have to be developed in the future.

It should be taken into consideration that the "Hydrogen and Gas markets decarbonisation package", December 2021, 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 elaborate on specific technical rules.

In order to use the electricity produced by RES in the most efficient manner, an integration in the electricity system should be the prioritised solution. The amount of avoided CO2 in the electricity system (fossil fired power plant) is significantly higher than in the hydrogen system (steam methane reforming):

To integrate the RES that is dispersed through the electric systems, it has to be connected both at the level of the distribution and to the transmission grid. Thus, robust and strong electricity distribution and transmission grids are preconditions for efficient RES integration in the electricity system and to ensure the system security.

From a system point of view, it should be decided in each moment if electricity can be injected in the electricity system without causing security violations. If this is not possible (due to grid congestions or oversupply) it could be used for conversion into hydrogen.

If electricity from existing RES is converted into hydrogen although it could be integrated in the electricity system, a fossil fuelled power plant may have to replace this electricity and the overall CO2 emissions rise. Thus, hydrogen from an electrolyser does not automatically reduce greenhouse gas emissions. A way out could be the principle of additional RES principle, as a mean to effectively contribute to the total reduction of CO2 emissions. Nevertheless, if these additional RES would be integrated into the electricity system, the CO2 emissions could be reduced even more efficiently.

3.2 Impact on electricity grids

The role of hydrogen in the power sector today is insignificant, with less than 0.2% of electricity generation" (The Future of Hydrogen. IEA, 2019) mainly for the use of gases from the steel industry, petrochemical plants and refineries. But there is potential for this to change in the future.

Particularly relevant impacts that an increased level of hydrogen demand and generation will have in the electricity grid will occur in terms of (i) volume of additional load in the system, (ii) location of that additional load, (iii) flow of energy in the grid (connection points), (iv) additional source of services to the electricity system, (v) potential additional RES generation for the production of (green) hydrogen.

In particular, grid-connected electrolysers shall have the following impacts :

- connection issues: location, capacity, grid reinforcements; coordinated grid planning within H2Valleys
- additional electric load to be managed (for the quota of power not generated on site), with consumption profile depending on the use case;
- dynamic characteristics, interacting with the wider electric system, to be modelled and included in stability simulations, control & protection schemes;
- possibility to provide ancillary services: frequency and voltage support, demand response, flexibility provider, to be utilised by the Grid Operator according to the efficiency and cost-effectiveness compared to other flexibility means/services.

These are discussed below.

3.2.1 Grid planning

The grid planning and system development activities, which shall for sure remain entrusted (or at least co-entrusted) on grid operators, will have to address increased challenges.

The "Hydrogen and decarbonised gas markets package", December 2021, foster integrated network planning between electricity, gas and hydrogen networks.

Indeed, 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 and – more broadly - P2X projects, impact on natural gas system, etc.). In particular, P2H represent one of the most impacting trend, due to its size and to the correspondent impact on natural gas system (H2 might substitute a quota or even all the natural gas flowing in today's pipes and users' devices).

This requires on one side the updating of scenario building framework, on the other side an important advancement in methodologies, modelling tools, simulation schemes for traditional grid planning, for adequacy resource assessment, and for resilience analysis. The first conceptual step is to identify if P2X initiatives must be included in the perimeter of energy projects to be assessed and how: external input to be forecasted or system resource to be planned in coordination with power & gas grids projects.

The main concepts to best integrate the upcoming set of large electrolysers into the evolving energy system can be summarised as follows:

- ✓ Location, logistic configuration and operational mode of new electrolysers are **strategic system architecture questions**; therefore appropriate coordination between hydrogen projects and electricity/gas developments is needed to ensure compatibility and optimality at energy system level.
- ✓ Regarding electricity grids, ENTSO-E has already developed some methodologies, like MULTISECTORAL PLANNING & DUAL ASSESSMENT of projects within its framework planning process TYNDP; more methodologies and application mechanisms need to be developed together with stakeholders and approved by relevant authorities.
- ✓ Impact on electric grid will be **an order of magnitude higher** than on gas grid; therefore it is paramount to include electrolysers and other components of hydrogen production in planning process of power system, rather than only tackling them as a connection request.
- ✓ The viability of the business case as well as the impact on electricity grids, is case- and country-dependent; 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.**
- ✓ Non-electrolysers hydrogen, as well as imported hydrogen, shall reduce the forecasts of domestic electricity demand.

3.2.2 Grid operations and flexibility services provision

Electrolysers, but more correctly $P2H_2$ projects (end-to-end approach), shall impact on system operation:

- For demand-driven P2H investments, the availability of a correspondent 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:
- possibility to provide system services: mid- and long-term storage, seasonal reserve, cross-sector energy balancing, to be utilised 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 (heat & cold, thermal storage, water desalination, multi-fuels engines, etc.).

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.

There are two types of flexibility expected from electrolysers:

- short duration: contribution to ancillary services for grid operation and to hourly/daily balancings;
- long duration: addressing the adequacy of the energy system as a whole, through storing excess RES energy for weeks, months or even seasons, to cater for periods of generation deficit/demand peaks; this can happen using the whole hydrogen storing capabilities (H2 production can follow RES variability while H2 demand is expected to be largely as baseload) as well as a buffer for the variability of the electric system, through reconversion into electricity in gas turbines hydrogen-ready; however this should be used as last resource option, due to intrinsic inefficiency of multiple energy conversions.

3.2.2.1 Short duration flexibility provision

Figures 7 and 8 show that in theory, electrolysers could provide most grid services, also depending on their technology and boundary conditions. According to several sources, alkaline electrolysers offer less flexibility when compared to PEM electrolysers, with alkaline electrolysers unlikely to offer grid services with an activation time of less than 30 seconds, with the current state of the art.

Flexibility capability of electrolysers

	Alkaline electrolyser	PEM electrolyser
Load range	15–100% of nominal load	0–160% of nominal load
Start-up	1–10 minutes	1 second–5 minutes
Ramp-up	0.2–20% per second	100% per second
Ramp-down	0.2–20% per second	100% per second
Shutdown	1–10 minutes	Seconds

Note: The ramp-up and ramp-down figures are percentage of nominal load.

Figure 7. Technical dynamic characteristics of electrolysers (Source: IRENA: “Renewable Power-to-Hydrogen”)

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

Figure 8. Flexibility technical potential from electrolysers

Some experiments have shown the capability of electrolysers to provide fast frequency response for utility-scale grid stabilisation. It was possible to confirm the ability to rapidly change the load point of the electrolyser in response to grid needs and to accelerate recovery in case of frequency deviation.

3.2.2.2 Long duration flexibility provision

Operating an electrolyser in a flexible manner is a promising operation mode for the energy system and particularly for System Operators. However, the demand profile for hydrogen will for sure not overlap with this hydrogen production profile. Hence, the hydrogen system (e.g., generation, loads and corresponding connections) needs also to adjust demand and generation (similar to the concept of flexibility). The following points describe how this adjustment can be provided within such hydrogen system.

A hydrogen network can provide flexibility to the hydrogen system by delivering hydrogen from any other source (remote electrolyser, import, storage, fossil production, etc.) or by transporting hydrogen away from the electrolyser to any other hydrogen sink. Thus, it provides flexibility in both directions.

Similar as the electricity network is a hydrogen storage that could be used to store and to withdraw hydrogen. It could be used for short term as well as long term storage. Appropriate for such a hydrogen storage are underground caverns. However, not everywhere such caverns exist or could be created. A hydrogen network could overcome such geographical differences between the source or sink and the storage of hydrogen.

The features of hydrogen system to act as large and long duration storage (Figure 9) show the advantages of hydrogen for complementing the other technical options, particularly valuable in the future System of Systems touched upon by a previous ETIP SNET publication; [Smart Sector Integration, towards an EU System of Systems].

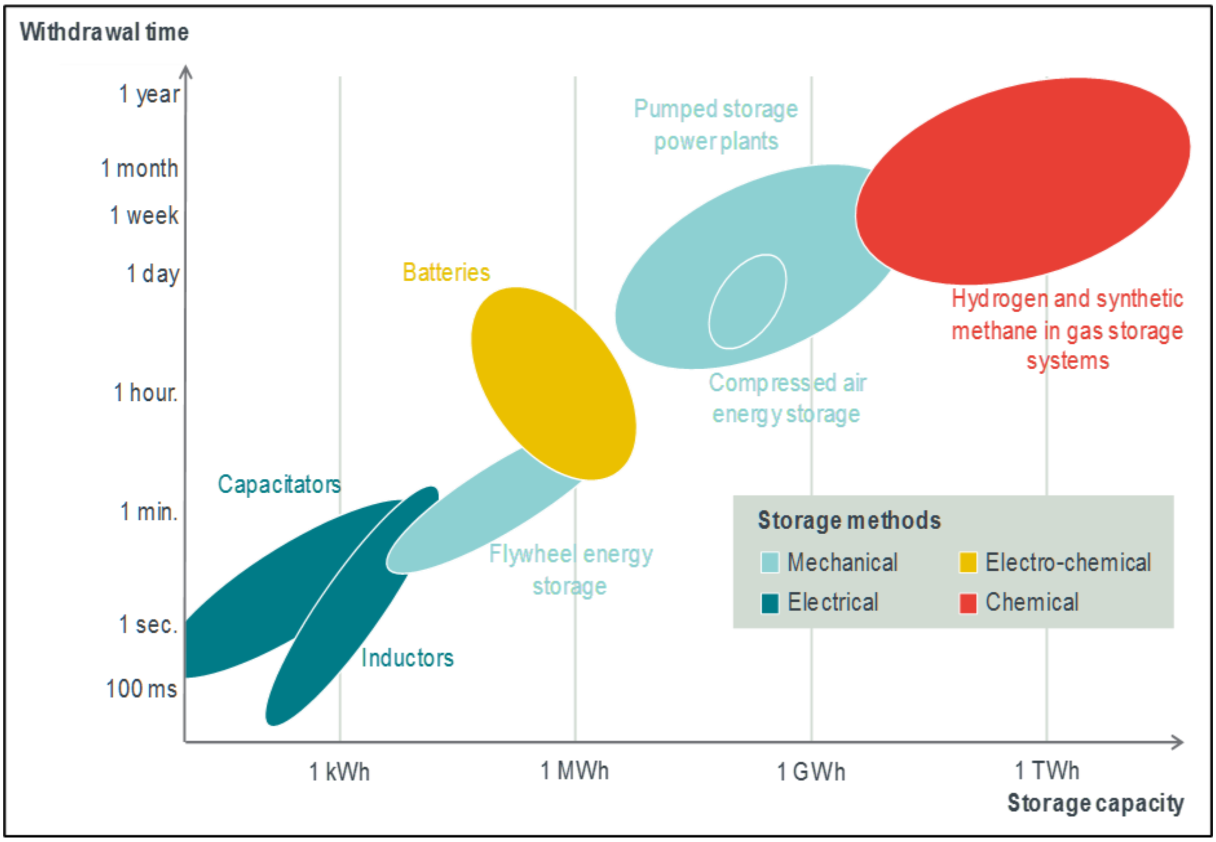


Figure 9. Benchmark of possible technologies for long duration storage

3.2.2.3 Considerations on flexibility expectations from hydrogen sector

- Electrolysers will be a new and important load for the grids, so they should contribute in terms of demand response ;
- Technically their rate of operation can be modulated to a certain extent: flexibility as demand response and balancing;
- Flexibility potential depends mostly on the connection configuration, operational mode, as well as storage capacities in the hydrogen system to de-couple electricity input from hydrogen output to final use;
- Hydrogen (both blue and green) can be stored seasonally, providing long duration flexibility to the wider energy system, very valuable service in a vRES-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 electrolysers: hydrogen/synfuels pipelines/grids, storages, logistics.

3.2.2.4 Projects on Flexible Electrolysers

During 2021, three new large scale projects were initiated in the context of a large Green Deal Call (Horizon 2020 LC-GD-2-2-2020), in particular related to the development and demonstration of 100 MW electrolysers capable of upscaling the link between renewables and commercial/industrial applications. Although the projects are planned to finalise in 2026/27, the first results indicate the following: (Horizon Europe (europa.eu), https://www.greenh2atlantic.com/, Greenhyscale | Greenhyscale, REFHYNE 2 – REFHYNE) :

- there is empirical evidence that electrolysers can provide grid balancing services to the Danish electricity system, which can react to a contingency in less than 10 seconds (a requirement for participating in the Frequency Containment Reserve (FCR) market in Europe).
- upgraded simulations models simultaneous considers the role of electrolysers for balancing in short-time scales (seconds) and mid-time timescales (hours, days), while quantifying additional economic and carbon benefits of different deployment levels of electrolysers.
- with the simulations done, a 100 MW capacity of electrolysers installed in the Danish grid would decrease overall operating costs and carbon intensity compared to the case of no electrolysers installed, if these 100 MW electrolysers contribute to the Frequency-Containment Reserve (FCR) service defined in Continental Europe (CE).
- one project aims to develop a novel, more compact 16 MW Alkaline (ALK) electrolyser module with fast-cyclability (20-100% in seconds) allowing to efficiently follow intermittent RES power supply
- one project electrolysis plant aims to become the world's largest electrolyser system qualified as a TSO balancing services provider, thereby reducing the cost of hydrogen to below 2.85 EUR/kg for an electricity cost of 40 EUR/MWh.

Develop and demonstrate 100 MW electrolysers upscaling the link between renewables and industrial applications

Acronym	Action	Total cost €	€ EU Contribution	TITLE
REFHYNE II	IA	147.365.995	32.431.618	Clean Refinery Hydrogen for Europe
GreenHyScale	IA	52.982.524	30.000.000	100 MW Green hydrogen production in a replicable and scalable industrial hosting environment
GREENH2SINES (GREENH2ATLANTIC	IA	76.614.020	30.000.000	100 MW flexible green hydrogen production process sourcing hybrid renewable energy & supplying green hydrogen to multiple end uses
Total		**200.348.519**	**92.431.618**	

Figure 10. List of 100MW electrolyser projects

3.3 Additional RES required and green labelling

The large scale utilisation of hydrogen for decarbonisation target requires that its production be made through low (and eventually zero) CO2 emitting energy sources. So, the main concept is to rely, after a transition period, only on green hydrogen, i.e. produced by RES. This implies to install a huge amount of new RES. This principle of additionality is necessary, otherwise using existing RES would not change the CO2 balance; actually, this "competition" for using RES, and effectively contributing to decarbonisation, is in place also for additional RES, since they could be used for decarbonising other sectors, like transport or buildings heating. Indeed, even the present electricity final uses need additional RES for decarbonising the pure electricity sector (the process is well on-going, but very far from achievement).

Therefore, Hydrogen projects, as well as other sector coupling projects relying on electrical RES, must be assessed with an accurate system view and suitable metrics must be used when assessing the decarbonisation potentials, in order to avoid cannibalisation among projects. Another fundamental implication is that the deployment of electrolysers (as well as of Electric Vehicles), is highly dependent on deployment of RES, so they must be planned jointly, to avoid the probable risk of mismatch in the (long) transition period.

Although understandable as rationale, it can be discussed why the additionality criteria should be applied only to hydrogen and not to other new uses of RES for electrification, like transport or heating.

3.3.1 EC Delegated Acts

In Feb. 2023, the European Commission has proposed detailed rules to define what constitutes renewable hydrogen in the EU, with the adoption of two Delegated Acts.*[2] The first under which conditions hydrogen, hydrogen-based fuels or other energy carriers can be considered as a Renewable Fuel of Non-Biological Origin (RFNBO). The requirements for the production of renewable hydrogen will apply to both domestic producers as well as producers from third countries that want to export renewable hydrogen to the EU to count towards the EU renewables targets.
Main concepts are reported below, while the figure 11 reports the state-of the art of the rules, which are undergoing a long and deep consultation process with hydrogen projects developers.

- Additionality principle: electrolysers use "new" renewable electricity accordingly to a robust methodology for unambigous calculations and assessment, avoiding double counting and greenwashing, for avoiding cannibalisation of other decarbonisation processes (e-mobility, electric heating, industrial processes electrification, etc.)
- Geographical correlation: for ensuring the utilised RES are not impaired by grid congestions, gauged at consistent granularity (bidding zone)
- Time correlation: for ensuring that utilised RES are not impaired by grid congestions, which occur and are assessed at power market granularity (1h / 15 minutes).

	Additionality	*Temporal correlation*	*Geographical correlation*
Electricity from the grid – general case	**Yes**	**Yes**	**Yes**
Electricity obtained from direct connection	**Implicit**	**Implicit**	**Implicit**
Renewable electricity surplus consumed from the grid (RES curtailment solved)	**Not requested**	**Implicit**	**Implicit**
Electricity from the grid when RES share exceeds 90%	**Not requested**	**Not requested**	**Same bidding zone**
Electricity from the grid when the emission intensity of electricity is lower than 18 gCO2eq/MJ	**Not requested**	**Yes**	**Yes**

Figure 11. Guiding concepts to hydrogen differentiation in the delegated acts

[2] Delegated regulation for a minimum threshold for GHG savings of recycled carbon fuels sets the methodology to calculate GHG emissions savings from RFNBOs and recycled carbon fuels
https://energy.ec.europa.eu/system/files/2023-02/C

3.3.2 Guarantees of Origin (GO)

Under the common assumption that hydrogen is valuable to the energy-climate transition only if it is CO2-free, or at least progressing towards this goal, a certification procedure must be in place, like Guarantee of Origin (GO), to be properly coupled with green electricity certification.

Guarantees of Origin for electricity are voluntary and are right now used by two different types of customers. Customers who have taken a first step in being more green; they buy certificates to claim a part of the yearly produced green energy. As the national yearly supply of green energy should be enough to cover all certificates, this incentivises production of green energy. A newer type of customer is the customer who wants his energy to be green at the moment of use. In the current certification system this is not possible. However, as the Guarantees of Origin should ideally work for both types of customers, the proposal is to include more information in the Guarantee of Origin. A time-stamp, production location and a CO_2 amount in the Guarantees of Origin can express added value to a customer and create a more transparent origin system.

As the electricity system works instantly and energy produced is not saved for a later time, the proposal is to call produced hydrogen only green when this is produced when the electricity production is renewable at same time of hydrogen production, for example, when the sun is shining and/or the wind is blowing. When there is no renewable electricity production, there is no option to create green hydrogen. The proposal is therefore to use the smallest possible validity time for the Guarantees of Origin when converting, per 15 minutes or per one hour. When the electricity has been converted to green hydrogen, this could of course be stored for a longer time when necessary.

It is not the intent to track every electron. However, the strong relation between renewable energy and green hydrogen in combination with the transparency of this in the Guarantees of Origin should attract parties to build electrolysers near the source of the renewable energy. This should help overloaded grids due to volatile renewable energy resources and lead to less curtailment of renewable energy in general.

3.4 Considerations on coordination with Gas System

According to the EC DG ENER the current market rules may have to be reassessed, as they currently focus on import of fossil gases. Two main pathways may emerge regarding the deployment of renewable and low-carbon gases, which may have a different pace across Europe: (i) a hydrogen-based infrastructure that will progressively complement the network for methane gases, (ii) a methane-based infrastructure in which natural gas will progressively be replaced by other sources of methane (i.e. biomethane and synthetic methane, possibly occasionally blended with hydrogen).

Two of the main aims of the Hydrogen and gas market decarbonisation package, which relate to the impact on grids, are (I) enabling the development of dedicated hydrogen infrastructure and market, allowing hydrogen to become a key component of the energy sector, (ii) Fostering more integrated network planning between electricity, gas and hydrogen networks.

In this context, the role of the natural gas transmission system operators (TSO) as an enabler of the hydrogen economy materialises through its assets and skillset, namely with (I) existing assets that can connect new hydrogen supply and demand, (ii) technical skillsets and know how in the development or management of assets needed for hydrogen transportation and (iii) commercial know how and geographical location that facilitates matching hydrogen demand and supply.

Natural gas TSOs can therefore play a key role in the creation of a hydrogen value chain and in the achievement of policy goals set around hydrogen. In order to fully play their role as enablers, natural gas TSOs need to be able to operate across the whole hydrogen value chain and collaborate with other players (including producers and suppliers) to the construction of such value chain.

Also, the grid planning considerations mentioned above for the electricity grids apply here, with the corresponding adaptations.

4. Market and Regulation changes needed

Regulation for gas and electricity grids was introduced with such grids networks already deployed and in operation; for hydrogen, EC approach is to develop its regulation before the grids are in place.

A first step is surely to bring clarity into the "colour debate" around hydrogen options and explore analysis based on carbon content/equivalence.

Applicable regulation to hydrogen/green gases grids must be established, in particular if it has to be derived from the current natural gas regulation (as suggested by some EC consultations), in relation to: grid access and use, grid ownership and governance, grid development decisions, grid costs and burden sharing, etc.

A gradual approach, depending on how H2 sector will evolve seems to be more suitable monitoring the emergence of natural monopolies/essential facilities or risk of abuse of dominant position (number of players, volumes, routes, market design). In any case, the basic principle of Regulation of the other energy sectors should be utilised: Third party access (TPA), Transparency, Non discrimination, Unbundling, Consumers' protection.

If the H2 sector will have characteristics like those of natural gas, then the gas regulation can be used as a starting point, with technical and market differences:

- Additional challenges due to integrated energy system perspective -> coherent approach across sectors for infrastructure planning
- Avoiding cross subsidisation between the gas and H2 network users.

As indicated by ACER and CEER, there is a need to "Clarify the scope of "entry-exit systems" to avoid misinterpretations and over-regulation of the distribution level. To ensure participation of local producers in the market, alternative solutions to full integration of transmission and distribution levels (for example, regarding balancing) should be considered. Also, the proposal should clarify that it does not have consequences on the perimeter of capacity allocations, and that, for tariff purposes, only the transmission level falls within the scope of the network code on harmonised transmission tariff structures for gas. In addition, the definitions for 'entry-exit system' and 'balancing zone' should be made consistent."

Other indications from ACER and CEER include partial exemptions of grid charges, taxes and levies for electrolysers:

- *„Ensure flexibility to phase in regulation of hydrogen networks by allowing derogations and exemptions, while keeping the 2030 target date. Due to the infancy of (large-scale) hydrogen technologies, regulators consider the pace at which the hydrogen market will develop in different Member States to be uncertain, making the 2030 target rather ambitious. In this context, European energy regulators repeat their call to legislators to ensure a sufficient degree of flexibility at the national level by having an approach with a clear political target date and establishing an effective system for derogations and exemptions to optimise the national trajectories for developing a hydrogen market. In particular, regulators suggest specific provisions on derogations for existing and 'geographically confined' hydrogen networks and on the unbundling rules applicable to hydrogen activities.".*

The following topics and aspects deserve attention from legislators, regulators, standardisation bodies.

- Create a level playing field for flexibility services to unlock access to electrolysers
- Promote market uptake de-risking/insurance instruments ("take or pay")
- Allow hydrogen mixed with natural gas to be used in existing natural gas infrastructure by defining a remuneration mechanism to encourage renewable hydrogen injection into gas networks
- Allow electrolysers to participate across the power sector (e.g. in some countries, only generators can access frequency containment reserves and frequency restoration reserves)
- Stimulate the creation of regulatory sandboxes for initial deployment of Hydrogen related solutions
- Necessary and consistent adjustment to tariff system, starting form the concept if the hydrogen grid has to be paid by all final consumers (of electricity/gas/hydrogen) or only by the hydrogen consumers
- Natural gas infrastructure may be converted to hydrogen transportation in some cases. A mechanism to modify the regulatory asset base (RAB) of natural gas transmission system operators, and adjustment of their tariffs, would need to be established

- Tariffs for natural gas networks need to be revised to facilitate the injection of hydrogen and tariffs for pure hydrogen networks need to be set so that a viable rate of return is reached by their investors.

Standardisation issues:

- Allow use of existing gas networks for transporting renewable hydrogen when cost-efficiently feasible and set relevant standards, including safety standards
- encourage blending of hydrogen with natural gas in appropriate proportions, harmonising the blending limits.

A further important point is to establish if grid operators (TSOs and DSOs) are precluded from investing/operating P2G, as it is for storage assets; the question arises because large electrolysers, capable of providing flexibility to the power system, could be directed in some of their operational modes by price signals or urgent system contingencies in order to support the system strenght and resilience. This concept is particularly applicable for the long duration flexibility, since there is no entity in charge of deciding and enacting the optimal hydrogen production proflie, storage levels and the reverse (utilisation of stored hydrogen, including the re-conversion to electricity). This aspect should be addressed in a broader view with the other energy systems coupled in asingle “System of Systems”, maybe in another ETIP SNET Position Paper.

5. R&D innovation needs

5.1 Where to concentrate and prioritise R&D efforts

Significant divergences are emerging across countries and regions, as national hydrogen strategies reveal varying attitudes towards hydrogen’s role in energy transitions, different use cases and different topologies. This signals a need to embrace diversity – eliminating a one-size-fits-all mindset – and enable differing technologies and use cases to be explored.

Demand-centric hydrogen perspectives are needed. The current hydrogen conversation often focuses heavily on supply, and not so much on the role of hydrogen users. Research could further explore what’s needed to trigger demand, with a specific focus on the development of hydrogen infrastructure and a global supply chain.

Scientific base must inform the “colour debate” (also called taxonomy of decarbonised gases), fixing the criteria to be adopted, the calculation methodologies and all relevant assumptions; the most rationale criterion is the carbon content/equivalence of a specific hydrogen stream, for all the different realistic cases of hydrogen production.

Technical R&D has several topics to address, mainly:

- Electrolysers technologies, materials, processes to enhance conversion efficiiency, reduce use of scarce materials, privilege flexible operation modes
- Non-electrolyser production technologies: pyrolisis, CCS for steam methane reforming
- Full use and repurposing of natural gas grids: pipes, valves, compressors, safety rules, etc.
- Transport on trucks, trains, ships, pipes
- Utilisation of underground caverns and salt reservoirs
- Final users devices for becoming hydrogen-ready
- Viability of distribution grids repurposing / new lines
- Mobility: hydrogen engines, fuel cells propellers, refuelling stations
- Promote technologies scale-up, investigating non-linear effects

Modelling and simulation techniques must be developed, tested, shared among the stakeholders and then consistently applied in infrastructures planning processes for assessing hydrogen projects with multi-system, cross-sector approach.

Coordinated efforts could be stimulated and enabled towards interoperable enabling digital solutions for monitoring, observability and big data analysis along the value chain. Technologies and concepts such as federated digital twins, big data and AI can contribute towards optimisation of operations and planning.

5.2 Where to concentrate incentives

Incentives are necessary as for any starting and promising technology.

For R&D activities, appropriate budget and efforts must be envisaged and maintained in national and European innovation programs, including pilot projects ensured by Regulators when they reach suitable demo stage.

For mid scale investments, only selected projects should be identified, when there are robust expectations of their viability having considered the whole use case, including end-to-end approach and life-cycle assessment. It would be short sighted to incentivise single steps of the use case, like the mere construction of an electrolyser or of another component of hydrogen system.

The forms of incentives also need to be carefully considered, privileging those compatible with the target to set up a market for hydrogen.

Electricity prices mechanisms, already subject to a on-going Market Design Reform should not jeopardise the competitiveness of hydrogen solutions, to facilitate access to low-cost renewable energy; indeed, elctrolysers should be incentivised to use excess or otherwise curtailed renewable production.

Mechanisms that help to monetise the hydrogen flexibility should be established, like partial exemptions of grid charges, taxes and levies for electrolysers, similarly to other situations in the market.

Electrolysers should be allowed to participate across the power markets sector (e.g. in some countries, only generators can access frequency containment reserves and frequency restoration reserves).

A dedicated Hydrogen refuelling network should be also incentivised at initial stage, to reach the minimum critical mass making it viable for an hydrogen vehicle driver to plan his journey or execute his duty service.

6. Key findings & messages

Hydrogen as a new system component

- ✓ Hydrogen is complementary to electrification for decarbonisation targets and not a target in itself. It has been used for decades as feedstock in the chemical industry, but in view of the prospective abundance of green electricity combined with the need to decarbonise harder-to-abate electrical final uses, makes hydrogen a promising means for deeper and faster decarbonisation in those uses.
- ✓ The first applications of green hydrogen are likely to be for substituting grey hydrogen in present industrial processes. However, electrolysers shall progressively become an additional system element, which implies to be planned and operated synergically with the rest of the energy system.
- ✓ Recognition of green hydrogen requires an ad-hoc scheme, valid across jurisdictions, for the infeed electricity encompassing:
  - Additionality principle, to avoid double counting and greenwashing, as well as cannibalisation of other decarbonisation processes (e-mobility, electric heating, industrial processes electrification, etc.), although it can be argued that applying it only to hydrogen can be discriminatory
  - Geographical correlation – for ensuring the utilised RES are not impaired by grid congestions, gauged at consistent granularity (bidding zones – the area within which there are normally no congestions and where the market prices are formed)
  - Time correlation – for ensuring that utilised RES are not impaired by grid congestions, which occur and are assessed at power market granularity (1h / 15 minutes – to ensure that the carbon content of the hydrogen is really below the threshold defined by the regulations).

Impact on grid operation

- ✓ Hydrogen system can provide flexibility, improve adequacy and resilience to the power system, through:
  - Short duration flexibility: grid services as demand response and balancing from electrolysers, to enrich the portfolio of flexibility means, provided that the electrolyser business case is compatible with the flexibility needs of the powers system
  - Long duration flexibility: storage of excess RES in large existing gas reservoirs (although unevenly distributed across Europe) for subsequent use as hydrogen (decoupling electricity and hydrogen load profiles), if competitive vs other means like reservoir hydropower, pumped hydro, Compressed Air or Heat Storage
  - Adequacy: using stored hydrogen for power generation in periods of prolonged no-wind no solar power generation, making this an additional revenue streams for hydrogen producers (thus aiming at a win-win situation)
  - Resilience: adding a new pillar for energy resources optimisation and infrastructures utilisation
- ✓ In order to better exploit the variability of RES, a flexible operation of the power system requires to decouple as much as possible, the profiles of green hydrogen production from hydrogen consumption.

  This means to have enough storage elements both in power system and in hydrogen system (assuming the situation is profitable for the players involved).

  Further research and development is needed along with regulatory sand boxes for safe testing and deployment of solutions. The ETIP-SNET HULCs provide the context for use cases development. There are 4 high level use cases impacted by the topics of the paper are HLUC1 "Optimal Cross Sector Integration and Grid Scale Storage", HLUC4 "Massive RES Penetration into the Transmission and Distribution Grid", HLUC5 "One-Stop Shop and Digital Technologies for Market Participation of Consumers (Citizens) at the Centre" and HLUC9 "Flexibility Provision by Buildings, Districts and Industrial Processes".

Impact on grid planning

- ✓ Any Hydrogen project should be designed and assessed starting from the end use case, volumes and costs, not from the supply side, which must follow the needs of the end user.
- ✓ From the energy system point of view, the deployment pace of electrolsyers should match the increase of the large amount of additional RES volumes required for producing green hydrogen, in order not to cannibalise other decarbonisation processes. The deployment should also be aligned with the corresponding industrial processes and their decarbonization paths.
- ✓ Hydrogen sector requires not only electrolysers, but also heavy infrastructural investments: transport (pipelines, grids, ships, etc.), storage, import facilities, integration with non-electrolysis hydrogen) , to be coordinated with gas and electricity grid developments, and also coordinated with end user needs.
- ✓ Hydrogen valleys are a promising configuration for starting the development of comprehensive use cases, characterised by positive business cases.

Key messages

- ✓ <u>One system view</u>: A holistic system perspective is necessary to establish an energy-efficient and infrastructure-efficient energy system.

- ✓ The viability of hydrogen projects is case- and country-dependent, requiring to analyse its entire <u>framework, boundary conditions and externalities</u>.
- ✓ <u>Operational modes</u>: Several operational modes of electrolysers are possible, depending on location respect to RES, hydrogen demand and grid connection, and they are characterised by distinctively different interactions and impact on the power system.
- ✓ <u>Win-win solutions</u> matching business needs (performances, load factor, electricity infeed cost, hydrogen delivery profile) with system requirements (stable operation mode, provision of flexibility) must be found in order to maximise the benefits for all stakeholders.
- ✓ <u>A coordinated planning</u>, from scenario-building to system impact and to consistent cost-benefit analysis of single projects, is necessary in order to best exploit existing infrastructures, avoid stranded assets and bottlenecks.
- ✓ For a smooth but fast transition phase, <u>repurposing the gas grid</u>, also through initial blending, is a viable and smart option to enable a gradual phase-out of natural gas and set-up of an hydrogen market.

Location, logistic configuration and operational mode of new electrolysers is a strategic system architecture question; appropriate coordination between hydrogen projects and electric/gas grid developments is needed to ensure compatibility and optimality at energy system level.

Appendix 1: Hydrogen role, demand perspectives and supply chain

A.1 Why we need green hydrogen

The Energy Transition has very strong decarbonisation needs. As depicted in Figure 12, this impacts mainly transport, buildings, power and heat plants, industry, with different rates and speed of deployment.

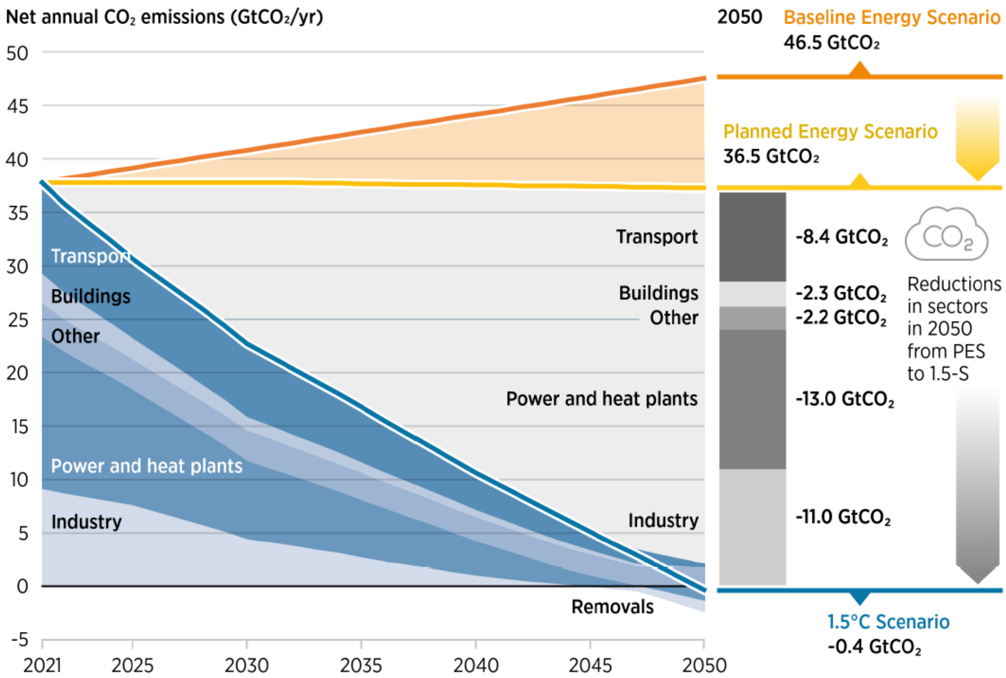


Figure 12. Size and evolution of different sectors' decarbonisation (source: Energy Transition Outlook, IRENA)

This Energy Transition process involves several building blocks (Figure 12A), including hydrogen as an important part of the solution, as well as solutions that do offer carbon-negative balance, such as bio/waste gasification for hydrogen and Waste-to-Energy+CCUS electricity for electrolysis.

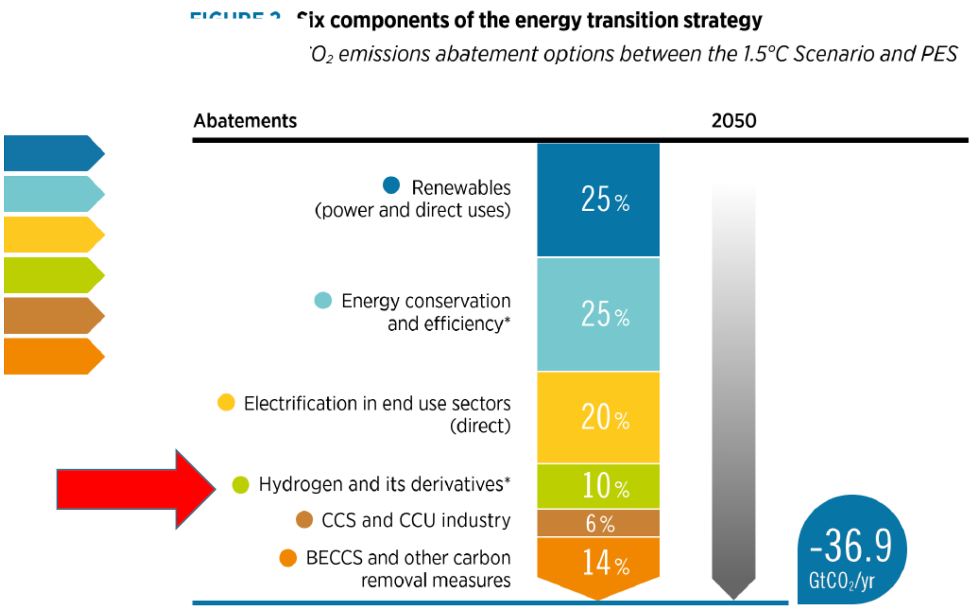


Figure 12A. Building blocks of Energy Transition; source: IRENA World Energy Transition Outlook)

Both electricity and energy molecules are needed in the decarbonisation process.The appropriate mix (from a cost-efficiency point of view) of using one or the other depends on the end-use. Indeed, there are non-electrifiable end-uses (cost would be extreme) where molecules will have a role. There are several use cases and the feasibility will depend on several parameters, including technology developments and geography.

Figure 13 assesses some relevant end-uses and the corresponding molecules/electricity appropriate choice, according to current state-of-the-art.

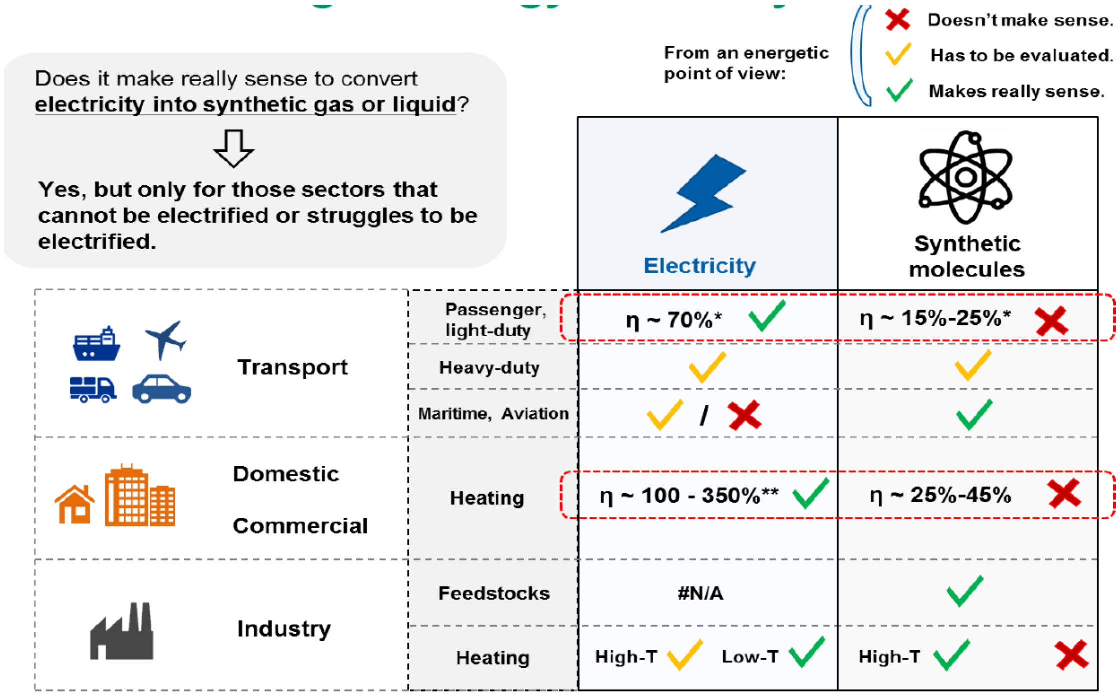


Figure 13. Comparison of feasibility for hydrogen and electricity end uses (Source: Terna)

In a broader context, the Power-2-Gas (P2G) process is depicted in Figure 14, where the P2G assets and the sector coupling link are key to decarbonise those sectors that are more difficult to electrify.

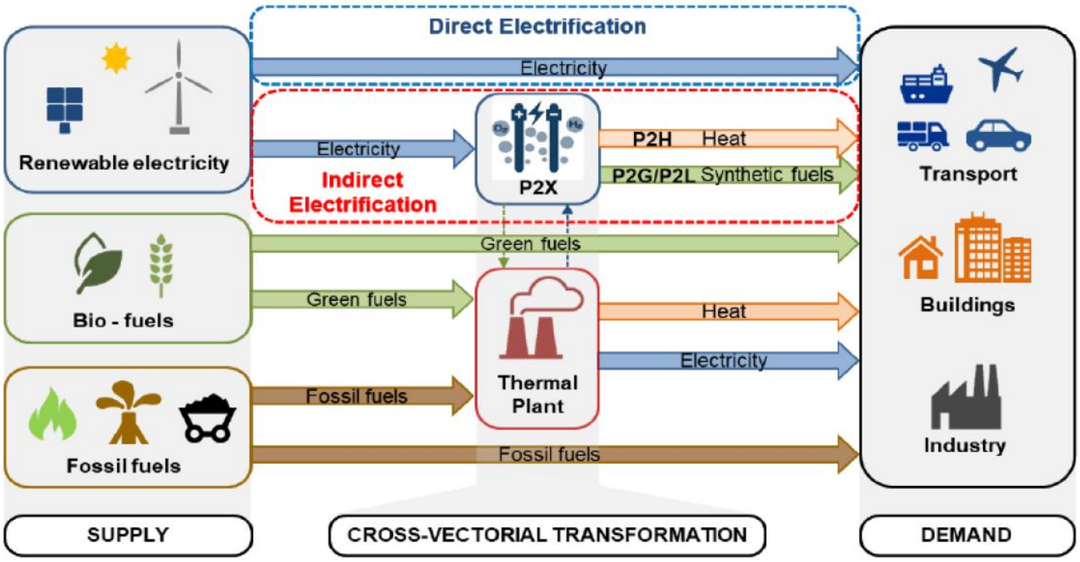


Figure 14. Coupling Sectors but also coupling production and demand of resources

A.2 Contribution of molecules for the decarbonisation

The EU has set ambitious climate targets towards 2050 to be compliant with the Paris Agreement. To reach these targets, the integration of renewable electricity sources is key; however not all energy demand can be electrified. Therefore, in a future energy system with a large amount of variable renewable energy sources (vRES), Smart Sector Integration (SSI) is another key prerequisite interlinking different energy carriers, sources, and final uses. In this context, "CO2-free" and in particular "green" hydrogen is one of most promising options to decarbonise processes/sectors which are difficult to decarbonise with electricity directly.

Since the taxonomy is still not unanimously defined and many different "colours" of hydrogen exist now, for the scope of this paper we would use the following definitions (Figure 15):

- CO2-free hydrogen is produced from non CO2 emitting energy sources
- Green hydrogen is produced via electrolysis and electricity from RES.

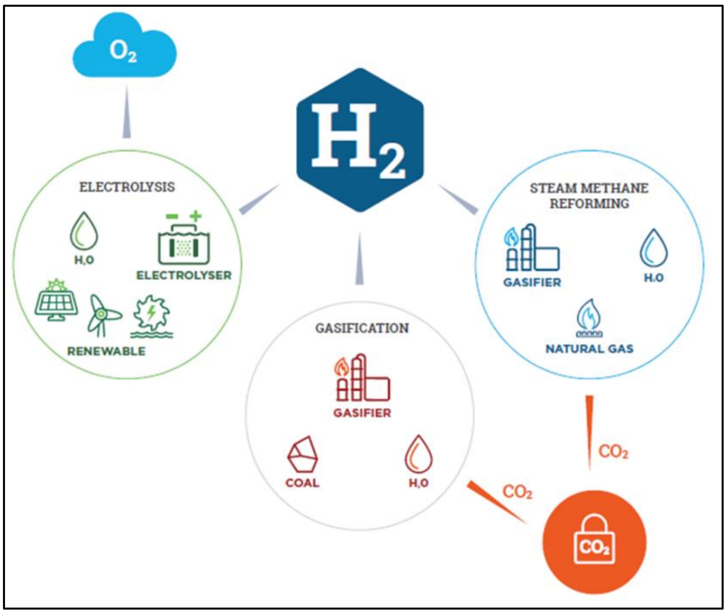


Figure 15. Production pathways for clean hydrogen—electrolysis and thermochemical reactions[3]

Hydrogen can be used (Figure 16) as a feedstock or a fuel and has different possible applications without emitting greenhouse gas emissions when using it, provided that it has been produced CO2-free. Furthermore, hydrogen (and its gaseous and liquid derivates) is an energy storage medium (e.g. to accumulate/store the electricity surplus in periods of time when the generation exceeds the demand and thus cannot be directly consumed) and an energy carrier (e.g. to transport energy instead of electricity). The European Commission, namely through its economic recovery plan, highlights hydrogen as an "*investment priority to boost economic growth and resilience, create local jobs and consolidate the EU's global leadership*"[4].

[3] *A Hydrogen Guarantee of Origin scheme for Australia*, Australian Government Departament of Industry, Science, Energy and Resources, Discussion Paper, June 2021.

[4] https://knowledge4policy.ec.europa.eu/publication/communication-com2020301-hydrogen-strategy-climate-neutral-europe_en

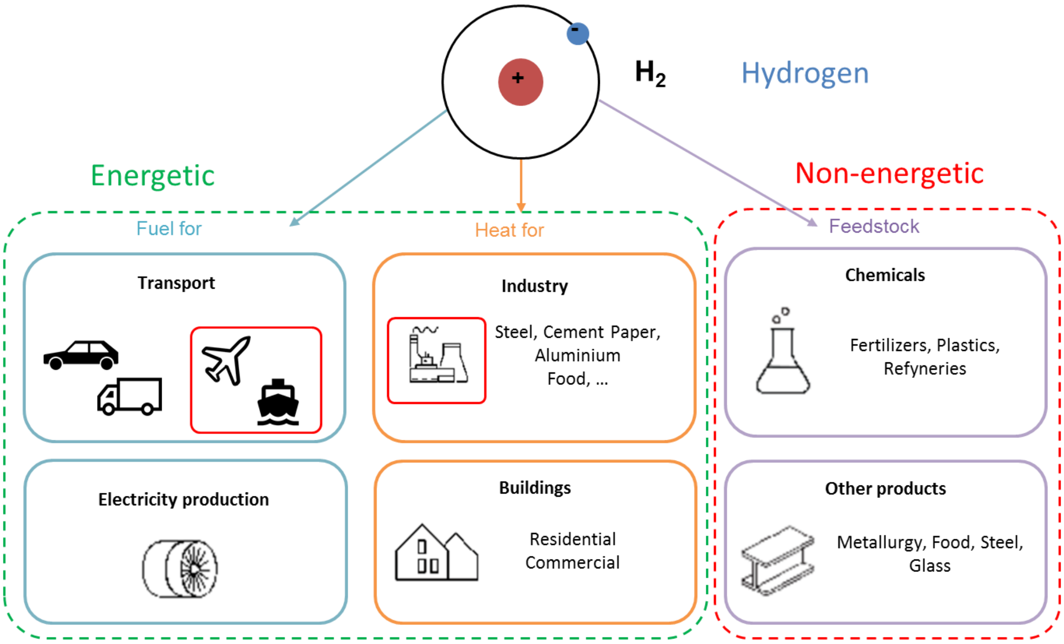


Figure 16. Multiple uses of hydrogen for a decarbonised economy (Sources: IEA, Bloomberg New Energy Finance, Terna)

A possible view of the "Hydrogen System" and its configurations in the context of grids and energy systems can be depicted as indicated in Figure 17. The following can be seen: production of H2 from renewable sources, use of H2 for mobility, industry and electricity grid services, storage of H2 and interaction with the natural gas grid both for pipeline injection and for reformation.

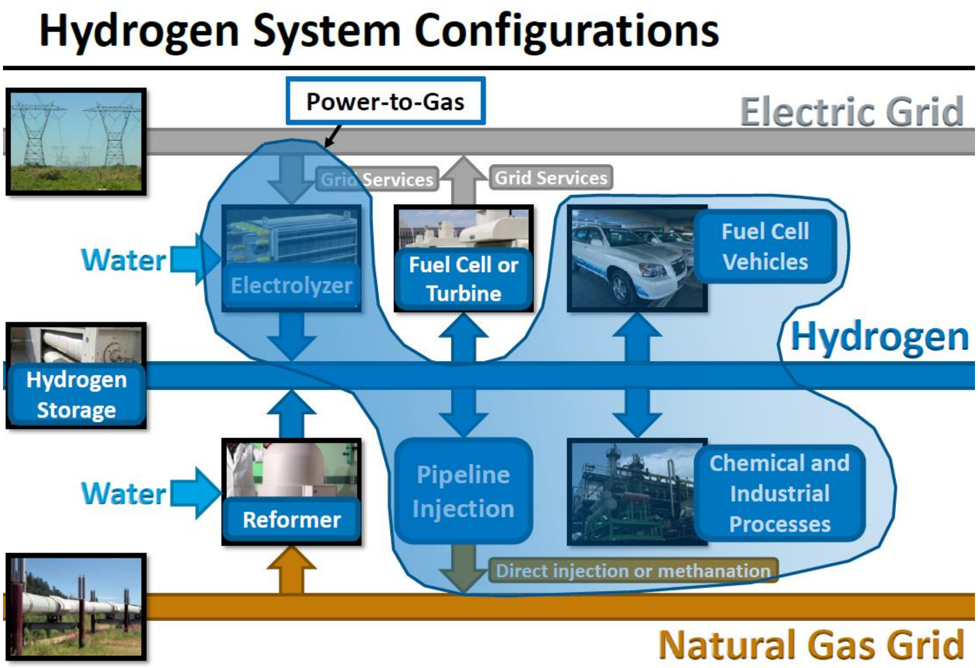


Figure 17. Possible Hydrogen System Configurations [Source: Gardiner] (P2G highlighted in blue)

A.3 Hydrogen utilisation and demand

In this Annex we will discuss the demand for hydrogen, starting from the current situation and taking into consideration the expected future demand, both from existing application and also from new uses. These developments will influence the impact that hydrogen will have in power grids. Existing demand relies on petroleum-refining process and ammonia production. In 2018, the worldwide demand of hydrogen reached 100 million tons per year [5], including dedicated production and by-product production, growing more than 300% in the past 40 years (Figure 18).

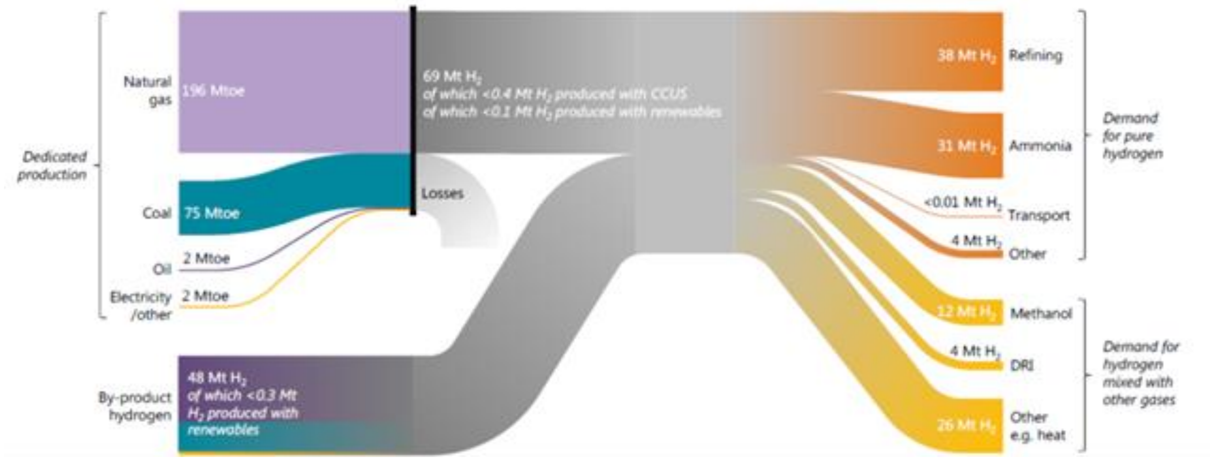


Figure 18: The fossil fuel input (left site) is related to Mtoe (oil equivalent) and the hydrogen output (right side) in MT (Sources: IEA and Bloomberg New Energy Finance, year 2018).

The annual worldwide demand for pure hydrogen is about 70 million tons in total, from which:

- 38 million tons for the refining sector
- 31 million tons for the ammonia production
- 4 million tons for other usage

The rest of the demand is used in a "mixed form" like methanol (12 million tons), etc.

The demand is currently covered by hydrogen produced from natural gas and coal, and associated CO2 emissions are significant. It could be assumed that this is the level of demand to be covered by pure hydrogen in the future, while eliminating other types of hydrogen.Updated information from the IEA from 2021, estimates that global hydrogen use is expected to expand from less than 90 million tons in 2020 to reach 530 million tons in 2050 (Net zero Emissions Scenario), representing 10% of global final energy demand. In the next sections we address the areas hat explain this increase in global hydrogen demands.

A.3.1 Future demand of hydrogen

As one of the decarbonisation pillars, hydrogen demand is set to rise, with industrial high temperature processes, heavy transport (hard-to-abate vehicles, like planes and ships), and potentially building uses switched from natural gas, receiving the most attention. Europe hosts the most announced industrial projects, in the U.S. there are ongoing projects on hydrogen power generation and Asia leads on fuel cell transport. Plans to heat buildings or entire cities with hydrogen are emerging, particularly in Korea and U.K.

In line with the EU's climate goal, industry should achieve net-zero greenhouse gas emissions by 2050. While decarbonising industry is a major challenge, industry has many options for achieving climate neutrality. Electricity used in industrial processes can be decarbonised by switching to generating electricity from renewable sources. Processes that require heat can also be electrified, but this becomes more difficult as temperature requirements increase. To decarbonise these processes, post-combustion Carbon Capture and Storage (CCS) or low carbon and

[5] International Energy Agency, "The Future of Hydrogen" (2019)

renewable fuels, including renewable hydrogen or biomethane, can be used. If the process requires carbon-based raw materials, biomass or synthetic raw materials can replace the fossil equivalent currently used. Finally, recycling and efficiency measures can further reduce the need for primary energy and raw materials, in line with the principle of the circular economy.

There are four main elements where the demand for hydrogen is increasing. These are[6]:

Industry

- Renewable hydrogen is crucial for industrial ecarbonizedon pathway. This is particularly relevant for iron and steel, ammonia, as well as fuels productions where hydrogen is primarily used as feedstock. The hydrogen demand in these sectors can be expected to increase to 238 TWh in 2030, 692 TWh in 2040 and 983 TWh in 2050.
- An additional demand could come from medium and high temperature industrial heat processes where hydrogen can partially substitute the current use of natural gas leading to at least 56 TWh in 2030, 165 TWh in 2040 and 217 TWh of demand in 2050. However, it can be costly to convert high-temperature processes, e.g. steel furnaces, to hydrogen-only processes. It will be associated with the need to replace the entire infrastructure currently used for the production.

Transport

- In transport, next to electrification and biofuels, there is a clear role for about 300 TWh per year of hydrogen as a fuel. Additional hydrogen will be needed to produce synthetic fuels in aviation. In 2050, hydrogen is forecasted to power 55% of trucks, 25% of buses, and 10% of airplanes. The demand for direct hydrogen in the transport sector in 2050 can be expected to be 285 TWh, with 68 TWh in aviation and 217 TWh in heavy road transport. Direct hydrogen is forecasted to account for 12% of total transport energy demand in 2050.
- Renewal hydrogen in transport is recognized as the fuel of the future. It is assumed that transport will be the primary source of renewable hydrogen consumption. Hence, the demand in this sector of the economy will grow in the future. The rate of this growth will depend on the development of hydrogen refining infrastructure and the demand for hydrogen vehicles.

Power

- The value of hydrogen over most other flexible power options is that it can be supplied and stored in large quantities at relatively cheaper investment costs, making it particularly appealing for long-duration storage. Hydrogen can cost effectively integrate and provide resilience to the highly electrified net-zero energy system (and economy) of the future.
- Hydrogen is an ideal fuel for providing carbon free balancing power in moving to a 100% renewable power generation system.
- Hydrogen in central power stations or decentral power plants can be used in gas turbines, gas engines or fuel cells. Hydrogen used in CHP plants allows high fuel utilization rates of 90% and more.
- Hydrogen in the electricity sector can be used throughout the value chain, i.e. in electricity generation processes (this can be done without replacement, as there is not necessarily "either gas or hydrogen" operation or hardware; already today there are gas turbines that allow for very high hydrogen content blended with natural gas (> 50% by volume), and by 2030, there will be gas turbines which can run on 100% hydrogen but (still) also on 100% natural gas (and any mixture in between), making gas turbines are a very flexible "hydrogen sink" when hydrogen supply is volatile – as its generation is based on surplus renewable power – or hydrogen cannot be stored anymore).

Buildings

- These include residential uses and a strong component related to heating and cooling.

[6] EUROPEAN HYDROGEN BACKBONE, Analysing future demand, supply, and transport of hydrogen, June 2021

- Heating in buildings will be ecarbonized using a range of technologies with significant regional variations. The hydrogen demand depends on renovation rates, the relative shares of biomethane and hydrogen, and the mix of heating technologies.
- The distributed uses of hydrogen imply to modify , and in many cases to substitute, the devices of the final users (e.g. burners, home boilers, cooking facilities, etc.), which is a strong barrier, both in terms of cost (to be born by the final user itself) and in terms of behavioral changes. Therefore there is a consensus that these uses shall be the last ones – if at all – to be converted to hydrogen.

A.3.2 New final uses (replacing fossil fuels)

The greatest potential for the development of hydrogen is transport, that is cars (passenger and delivery), trains, aviation and ships. Moreover, new consumers of hydrogen (also blend with gas) are end-users who use gas for everyday activities (cooking, heating). It can also be expected that new users are the current coal or oil-fired boiler houses for heating blocks (apartments).

Low-power cogeneration systems, including hybrid systems – fuel cells (possible implementation of hydrogen technologies today); hybrid systems in the form of a gas turbine coupled with a fuel cell (hydrogen after popularization of commercial installations). Usually, cogeneration processes are based on natural gas. Assuming that today hydrogen is a more expensive fuel than natural gas, and the cost of OPEX is the dominant cost in the operation of cogeneration systems, the condition for choosing hydrogen instead of natural gas as a fuel source for a cogeneration unit will be achieving better energy efficiency or a competitive price. In order for hydrogen cogeneration units to be a cost-effective technology, it is required that the demand for heat increases with the demand for electricity, then hydrogen cogeneration units will be able to create a niche in which the production of heat in combination with production and electricity will bring a greater benefit compared to high-efficiency electric heat pumps[7].

Medium and large-scale power engineering – in the medium power gas technology, hydrogen can be used for peak powers (combined systems of gas technologies using blended hydrogen or synthetic fuel). The green hydrogen produced can be used as a fuel to generate energy as gas turbines and gas engines can operate on hydrogen, supporting a variety of industrial applications, including steel mills, refineries and petrochemical plants, where the blending of hydrogen in the operation of gas turbines is at a level of not less than 50%[8].. These are potential elements where hydrogen, can be used (the scale will depend on the technical efficiency of the processes and the price / performance ratio for which a given level of efficiency will be obtained).

Hydrogen as a fuel for a gas turbine can be used in two main ways:

- combustion in pure oxygen (which is a by-product of hydrogen production),
- the use of a classic gas turbine, collecting air for combustion from the environment and discharging exhaust fumes to the environment, presumably operating in an open cycle, since in the medium/long term combined cycle might fade away, while open cycle (could) remain in operation for emergency/peak demand conditions.

In the first case, there is a closed thermodynamic cycle, i.e. an increase in the amount of water in the cycle as a result of hydrogen oxidation. As a consequence, the excess of the medium (generated water) is discharged into the environment. In the second case, installations based on currently developed gas turbines can be implemented, leading their evolution from co-combustion of hydrogen with a small energy share to the combustion of pure hydrogen in the air. This conceptual trend is currently dominating work on the use of hydrogen for combustion in gas turbines. All producers of high-capacity gas turbines and a number of manufacturers of smaller turbines declare their ability to produce machines capable of co-firing hydrogen with natural gas now or in the next few

[7] Australian Government, *Australian hydrogen market study Sector analysis summary*, Advision, 24 may 2021, pp. 70-71.
[8] Goldmeer J., *Power to Gas: Hydrogen for Power Generation. Fuel Flexible Gas Turbines as Enablers for a Low or Reduced Carbon Energy Ecosystem*, General Electric Company, 2019, pp. 13-14, https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20Power%20to%20Gas%20-%20Hydrogen%20for%20Power%20Generation.pdf

years (until 2023). Likewise, everyone declares the ability to prepare solutions enabling the production of turbines burning pure hydrogen by 2030. The scale of the demand for hydrogen in energy gas turbines is one of the significant challenges in the current state of technology (the production capacity of currently produced electrolysers).

Hydrogen in internal combustion engines (gas engines) has been demonstrated successfully:

Internal combustion engines as spark ignited engines (gas engines) are able to run on all type of gaseous fuels. From low BTU gases, raw biogas, landfill gas, sewage gas, steel gases with high hydrogen content to biomethane, synthetic methane and natural gas. Recently gas engines in the output range of a few 100 kWs to more than 1 MW have been demonstrated to run on 100% hydrogen. Those engines can be built to run on natural gas today and be converted later on to H2-engines. A hydrogen readiness concept has been developed by Eugine, the European gas engine association (Figure 19).

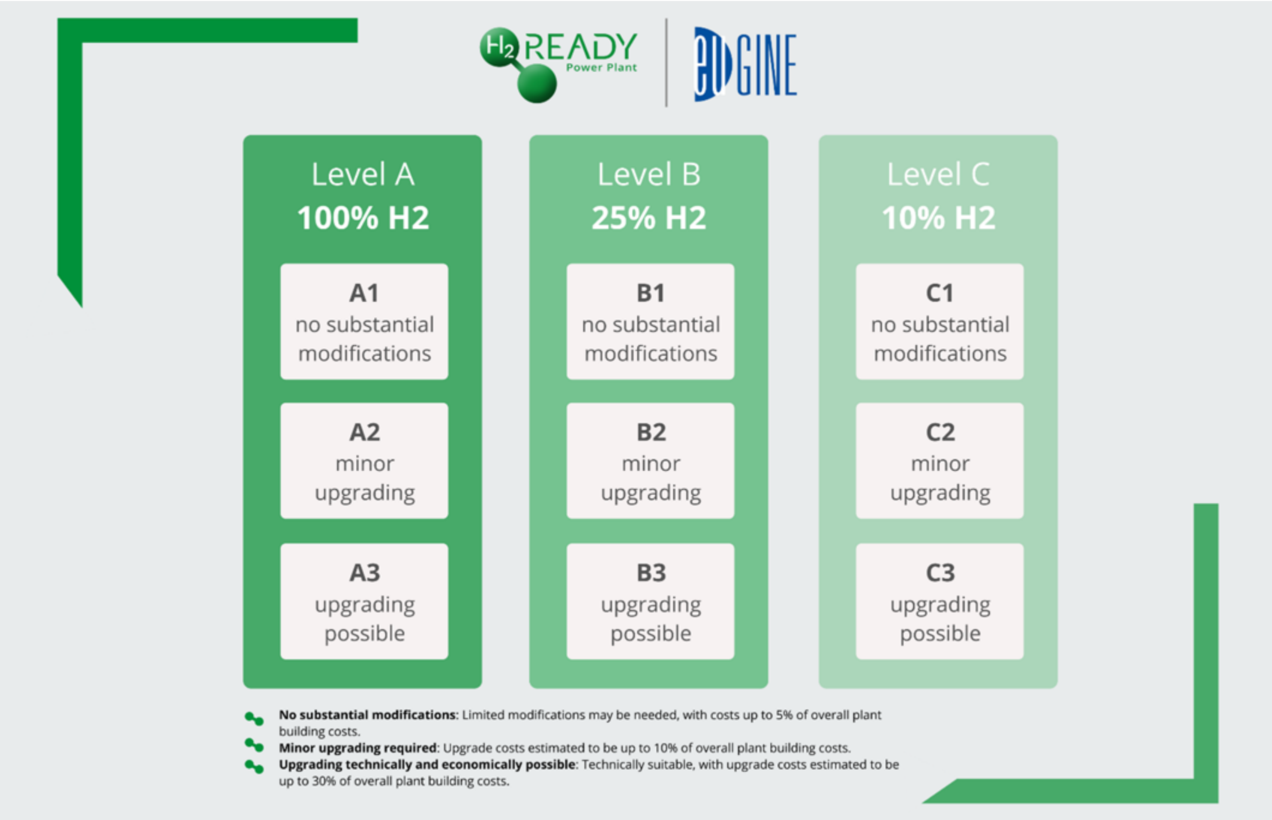


Figure 19. Hydrogen readiness concept for gas engines (source: EUGINE)

A.3.3 Hydrogen as energy carrier in place of electricity

Another potentially relevant use of hydrogen is as energy carrier in place of electricity, in cases where the logistics and economics justify such an option. Indeed, hydrogen can be transported over long distances and high capacities. As a result, the location of the conversion from electricity to hydrogen in an electrolyser and thus the electricity and hydrogen infrastructure can be optimised. Heat for example cannot be transported over hundreds of kilometres and moreover has different qualities (temperature levels, heat transfer media etc.). Also for power-to-mobility the electricity is needed where the mobility is needed (e.g. at a charging station).

A.4 Hydrogen production and supply

The Hydrogen supply chain can be schematically represented as in Figure 20 :

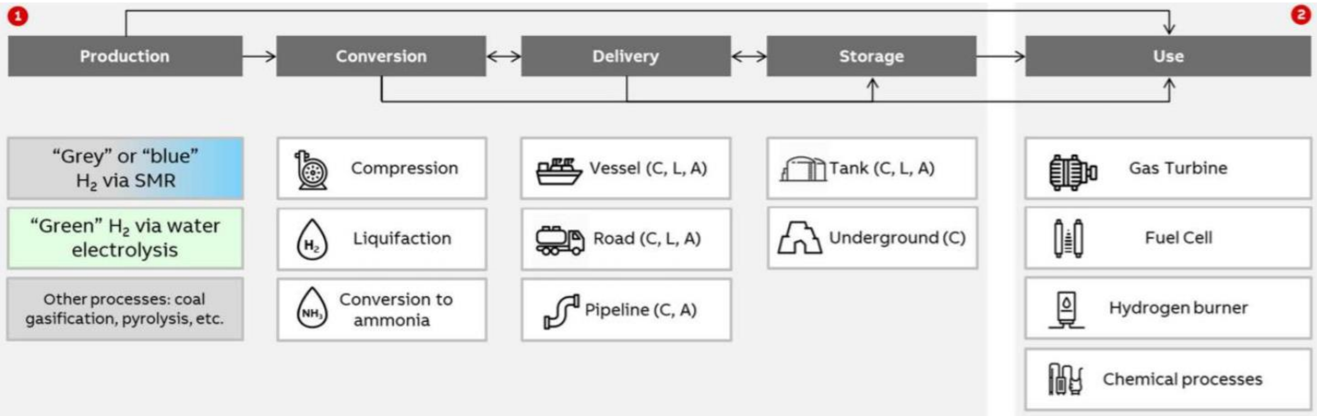


Figure 20. Supply chain for end users of hydrogen (Source: Hitachi Energy)

In the following sections we will address the different phases including production (or import when there is no endogenous production), transportation and distribution, and storage. All these different aspects have influence on the power grids, in particular due to their locations and volumes.

A.4.1 Production

In 2018, around 99% of the hydrogen demand was satisfied using fossil fuels (oil and methane), or via fossil fuels derived electricity. Some of the hydrogen is produced as a by-product (e.g. from the chloralkaline or from steam-cracking processes). But most of the hydrogen is produced on purpose by steam methane reforming. With different steps of the process, methane and water are producing hydrogen and carbon dioxide. Thus, the production of so called grey hydrogen (without capturing CO2) is highly polluting: producing one 1kg of hydrogen (ca 39 kWh)[9] from natural gas (i.e. methane) releases circa 10 – 14 kg of carbon dioxide (CO2).[10]

Although it is expected that electrolysis will be dominant in the green-H2 market, one should not fail to acknowledge that other means of producing hydrogen are on their way to market and, although electrolysis will most likely remain the main source of hydrogen, the alternative sources will have some non-negligible benefits. As an example, gasification of biological residues and bio-fractions of waste will contribute to:

- negative CO2
- circular economy by utilizing end-of-life wastes
- add production of H2 in locations where there is abundance of bio-residues and scarcity of sun and wind.

According to I Merkit projection such gasification is going to be competitive also from costs point of view.

Similarly, one should acknowledge similar benefits from Waste-to-Energy electricity.

Since the electrolyser on large scale is the future technology to provide hydrogen, the source of the electricity for their operation is crucial as to guarantee the decarbonisation benefit of using hydrogen to replace fossil fuels.

Wind generation, in particular on-shore plants, can be considered as a mature technology with an extensive field experience provided by thousands of projects in places all over the world. Offshore renewable energy is one of the renewable energy technologies with the greatest upscale potential[11]. Solar photovoltaics (PV) has been also used for many years and the learning curve has been reduced its cost significantly. All these three vRES

[9] For a better comparison we also indicate the energy content based on the higher heating value of hydrogen.
[10] https://www.sciencedirect.com/topics/engineering/methane-steam-reforming
[11] An EU Strategy to harness the potential of offshore renewable energy for a climate neutral future, COM (2020) 741 final

technologies have an expansion potential in Europe, depending on geographical conditions, and are considered for green hydrogen production.

Hydropower plants with year-round stable capacity (ample basin and limited seasonality inflows) could also be, under some conditions, a good match for electrolysers, but in Europe they are typically already committed to load-follow service (nowadays residual load), thanks to their very good dynamic performances. Furthermore, additional hydro plants in Europe seem only possible in rare situations. The advantage of hydropower as a source of energy to produce hydrogen is its high availability and hence the high utilization rate it can provide for the electrolysis plants. The resulting cost advantage is currently generating considerable worldwide interest in hydropower as a reliable energy source to produce hydrogen on a large scale. For developing and emerging countries with high hydropower potential in particular, this opens up new export opportunities. This is of utmost interest for Europe, which will face huge import demand as domestic renewables resources will never meet the demand for H2 generation.

Biogas or biofuels are themselves considered CO2-free energy vectors. However, producing electricity for electrolysers would compete with more efficient steam methane reforming to produce hydrogen directly from them (especially in case of greenfield clean biomass).

Geothermal is well-suitable, with some potential still to be exploited (e.g., Iceland), but problematic due to low energy density, i.e., low power capacity.

Nuclear energy, where still possible, is CO2-free and available as baseload profile generation, thus maximising the load factor of electrolysers. However, almost no additional capacity is envisaged in European Union in short- or medium-term perspective. Furthermore, the time for permission and installation of recent nuclear plants increased significantly, as well as the costs. Similarly, to vRES, also electricity generated by nuclear generating shall be directly used in this clean form.

There are several conversion options for a carbon neutral system, as depicted in Figure 21. These options are in the origin of one common classification of hydrogen according to colours associated with its carbon footprint.

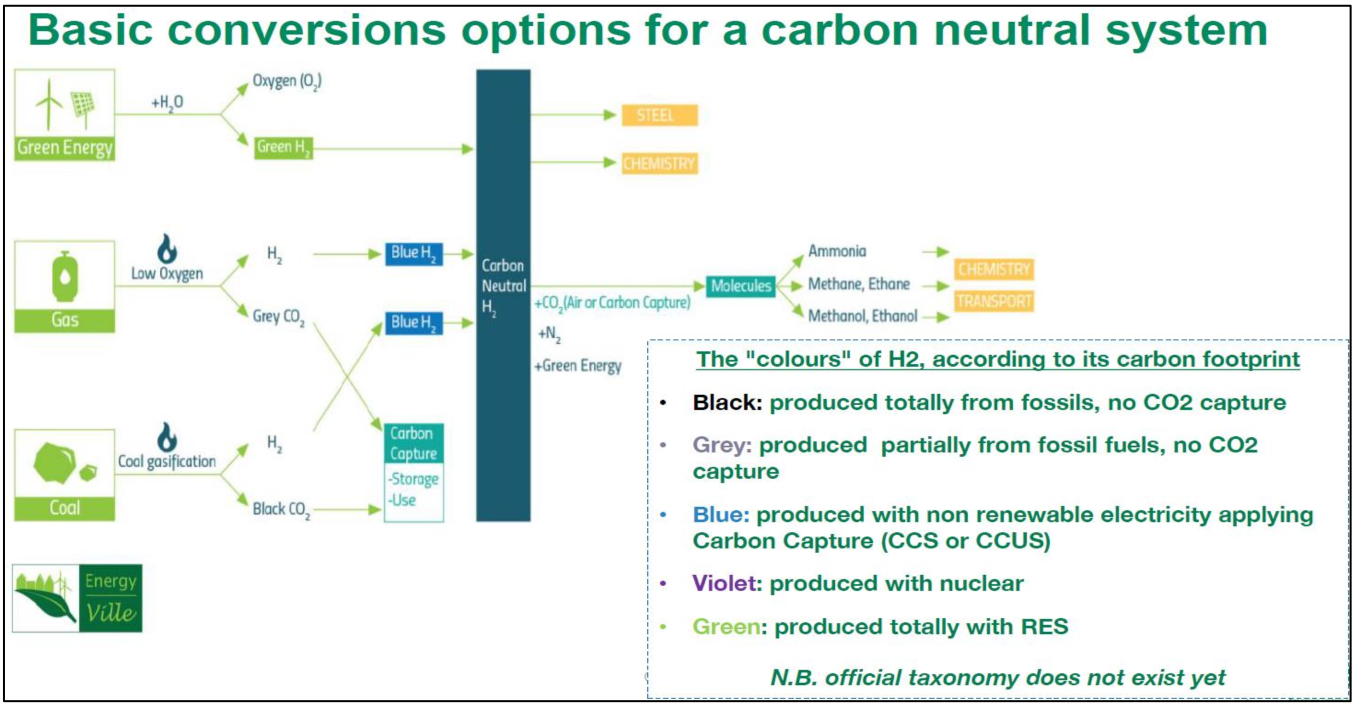


Figure 21. Conversion options (Source: Energyville)

An official regulation and taxonomy is still not available and additional views exist as depicted in the information from IEA in 2021 (Figure 22); however, recently EC is oriented to define the classification in terms of CO2 contents in the hydrogen produced and commercialised to the end users, therefore independently on the production process (no more "hydrogen colours"); only low and zero carbon content hydrogen shall be entitled to facilitations and incentives, according toitts effective decarbonisation impact.

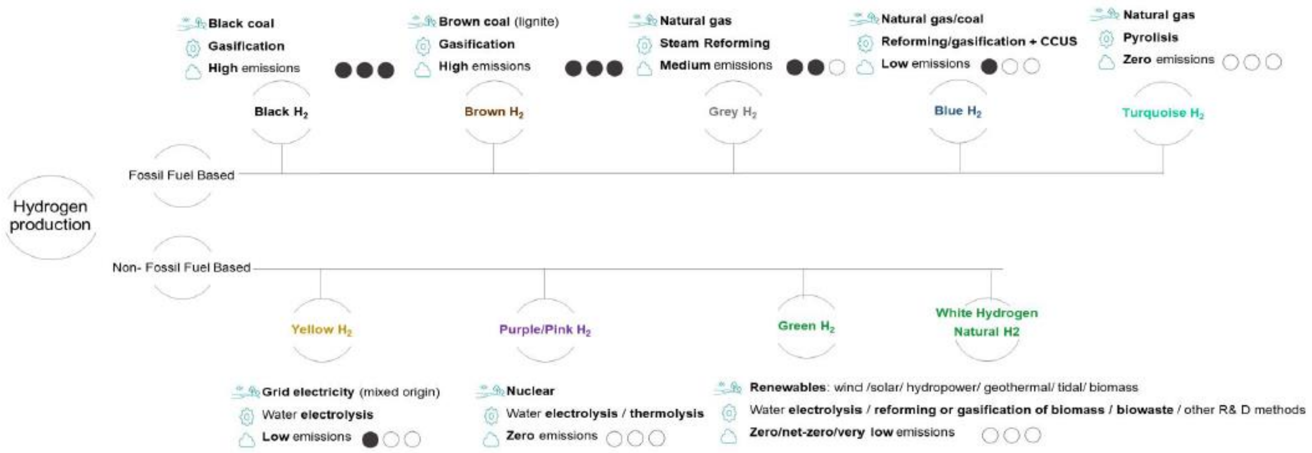


Figure 22. Sources of low/zero carbon hydrogen (Source: IEA TCP Hydrogen)

Hydrogen produced from renewable energy (mainly from wind and solar) via electrolysis will play an increasingly important role: the European Commission's Hydrogen Strategy[12] sets the ambitious goal to reach 6 GW of electrolysis capacity in Europe by 2024 and 40 GW by 2030.

Grid-connected electrolysers are of special interest for electricity grid operators. Two main aspects reflect the interaction with the electricity system: location/configuration and operation mode of the plants. They are addressed in the following section.

Connecting electrolysers directly to renewable energy sources through "dedicated" green hydrogen plants offers benefits where conventional grid-connected sources might not be practically feasible or economically viable. For example:

a) In regions where the potential for green hydrogen production is large, and electricity demand is already largely being covered by wind and solar, high additional capacities of wind and solar can be directly connected to electrolysers, saving on grid connections costs that would only be of use for a small percentage of the time.

b) Hydrogen can be stored cost-effectively over long periods of times, providing longer term storage and the ability to balance the electricity grid. This can improve the economics of renewable projects in areas where low renewable capture prices would have otherwise made the economics of projects unattractive; and

c) Hydrogen can be transported over long distances cost-efficiently, particularly when large scale repurposed existing pipeline infrastructure is used. Again, green hydrogen can help relieve pressure of the increasingly congested electricity grid with high penetration of intermittent renewables.

These examples, although subject to the presence of an adequate hydrogen delivery system, demonstrate the nuanced aspects of creating an integrated energy system, and highlight the importance of considering all solutions when assessing the hydrogen supply perspective. This section aims to make an objective assessment of the green hydrogen supply potential.

[12] A hydrogen strategy for a climate-neutral Europe, COM (2020) 301 final

A.4.2 Power-to-X concept

In the debate, often electrolysers and power-to-gas are discussed under the broader term of power-to-X, which includes several forms of energy to which electricity is converted (heat, cool, molecules). In most applications an electrolyser is the first industrial process to produce hydrogen and later other products are derived from hydrogen. Such products could be hydrocarbons like methanol or others.

Ammonia, for example, is quickly moving from another promising product to a reality. It is already used as energy carrier, and even used in power plants in Japan. There is a double benefit there:

1. there is already experience and infrastructure for NH3 as energy carrier

2. CO2 and NH3 can be transported on same cargo ships, so that a round trip would allow Japan to export its CO2 while importing NH3 from e.g. Australia.

Such material products can be used as energy carrier or reactant in further chemical or industrial processes. As a conclusion, the electrolyser could be treated as the physical interface of coupling electricity and hydrogen systems.

It has to be stressed that the power-to-X concept is basically a solution for absorbing/storing "excess" electricity (which cannot be directly used or stored it this clean form). Any conversion is inevitably associated/followed by energy losses – e.g. example in Figure 23.

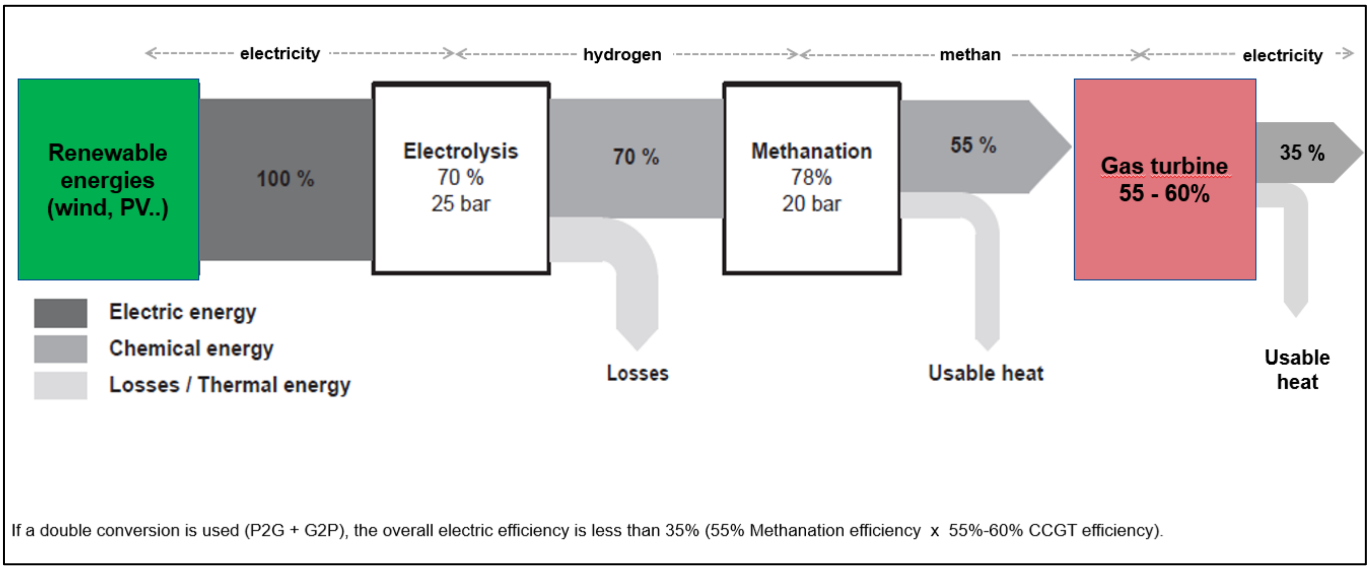


Figure 23. Multiple energy conversions and associated losses (Source: Hitachi Energy)

One of the elements identified as P2X technology is the Power to Gas (P2G) technology, which can be most simply characterized as the conversion of electricity into gas that may be subject to:

- storage for later use,
- further distribution,
- end-use through further processing or consumption.

The first step in the process is production of renewable hydrogen by electrolysis from renewable energy sources. This hydrogen can be used directly, blend with gases or subjected to a second step, e.g. by reaction with carbon dioxide to produce methane. Methane is a key component of natural gas and can be used directly in all of today's standard gas applications. CO_2 used in the methanation process is captured from air, biomass, biogas, bio-residues or waste (50% biogenic), to ensure a closed carbon cycle (Figure 24).

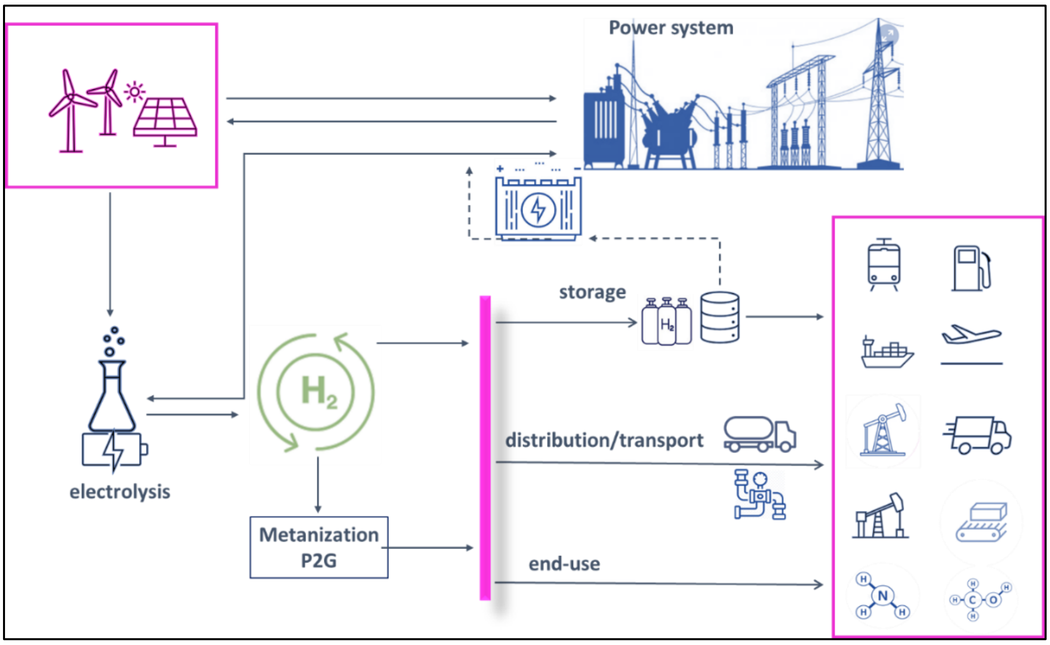


Figure 24. A simplified diagram of the hydrogen economy taking into account the Power to Gas (P2G) technology, assuming the production of hydrogen from renewable energy sources[13]

A.4.3 Import

Like other energy vectors, hydrogen can be produced locally or imported from regions having more favourable and cheap production conditions, compensating the transport costs. For developing and emerging countries with high hydropower potential in particular, this opens up new export opportunities at cheapest production costs. For Europe, where high consumption is forecast for industrial decarbonisation reasons, imports could come from neighbouring regions via pipeline (North Africa, Middle East, Russia, Iceland) or via ship from anywhere in the world. This shall pertain the domain of energy policy, and would reduce the number of electrolysers connected to European grids.

[13] Raport DISE/PSEW, Zielony wodór z OZE w Polsce, October 2021.

A.4.4 Hydrogen grid: transportation and distribution

For hydrogen applications to be competitive, a cost-efficient transmission and distribution is required.

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 centers via trucks, trains, refuelling stations, and smaller industrial users.

On the transmission side, longer distances can be covered by shipping, where hydrogen needs to be converted to increase its density. While several potential hydrogen carrier approaches exist, three carbon-neutral carriers – liquid hydrogen (LH2), liquid-organic compounds (LOHC) and ammonia (NH3) – are gaining most traction. The end use of hydrogen needs to be considered to determine the most cost-optimal solution.

As of today, only few dedicated hydrogen networks exist in Europe, especially to connect industrial sites in the same industrial area. With the upscale of green hydrogen production, as foreseen in the European Commission's Hydrogen Strategy, the installation of a so-called European Hydrogen Backbone is currently being discussed. Therefore, high investments of €43 to €81 billion in the retrofitting of natural gas pipelines and new hydrogen pipelines are foreseen[14] to attain a hydrogen network of circa 40 thousand kilometres until 2040. Such a dedicated gas network would allow to transport hydrogen cost-efficiently across Europe.

From a power system perspective, such a hydrogen network would be helpful to provide flexibility to the energy system, see the later paragraph on this topic. Furthermore, it allows to import hydrogen that arrives at the border of the EU or each country and has to be further transported to purchasers.

Indeed, 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.*"

Also, 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 elaborate on 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.

Further distribution of hydrogen can take place via gas networks or specialized land or sea transport. For gas networks, there are three options for integrating hydrogen into the gas system:

- blending hydrogen with natural gas in the existing gas infrastructure,
- development of a dedicated hydrogen network by transforming the existing gas infrastructure or building a new hydrogen infrastructure, and
- by methanation, which involves capturing CO2 to produce e-methane injected into the gas network.

[14] 23 gas infrastructure companies from 21 countries presented the report "Extending the European Hydrogen Backbone. A EUROPEAN HYDROGEN INFRASTRUCTURE VISION COVERING 21 COUNTRIES" in April 2021 https://gasforclimate2050.eu/?smd_process_download=1&download_id=669

The transmission pipelines can be adapted to a 10% hydrogen-natural gas blending because the hydrogen transmission requires higher pressure to be supplied by compressors (due to the lower density of hydrogen than natural gas), which devices have the lowest hydrogen tolerance. Currently used compressors in transmission networks allow for pumping 10% level of blended hydrogen

On the other hand, distribution networks, due to lower pressures, are characterized by a higher tolerance - it is possible to transmit 50% of the hydrogen blending. Only some parts in the natural gas distribution system present a very high tolerance - polyethylene distribution pipelines can transport up to 100% hydrogen.

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 has to be transported either in its naturally available form (e.g. natural gas) or converted into electricity or hydrogen. Nowadays, hydrogen is produced at the industrial sites where high quantities are used and the fossil energy (mostly methane) is transported to that locations. In the future, this will probably change, and hydrogen needs to be transported.

Depending on the distance and quantities to be transported, different alternatives can be considered (Figure 25 and A16). For short distances (< 1000 km) and rather small quantities (< 10 tons/day), hydrogen is usually being compressed (or liquefied) and transported in tankers via road/rail.[15] For larger distances and quantities, hydrogen can be compressed and transported in gas pipelines. In the future, hydrogen could be converted into a liquid medium such as ammonia and be transported over global distances by shipping. 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.

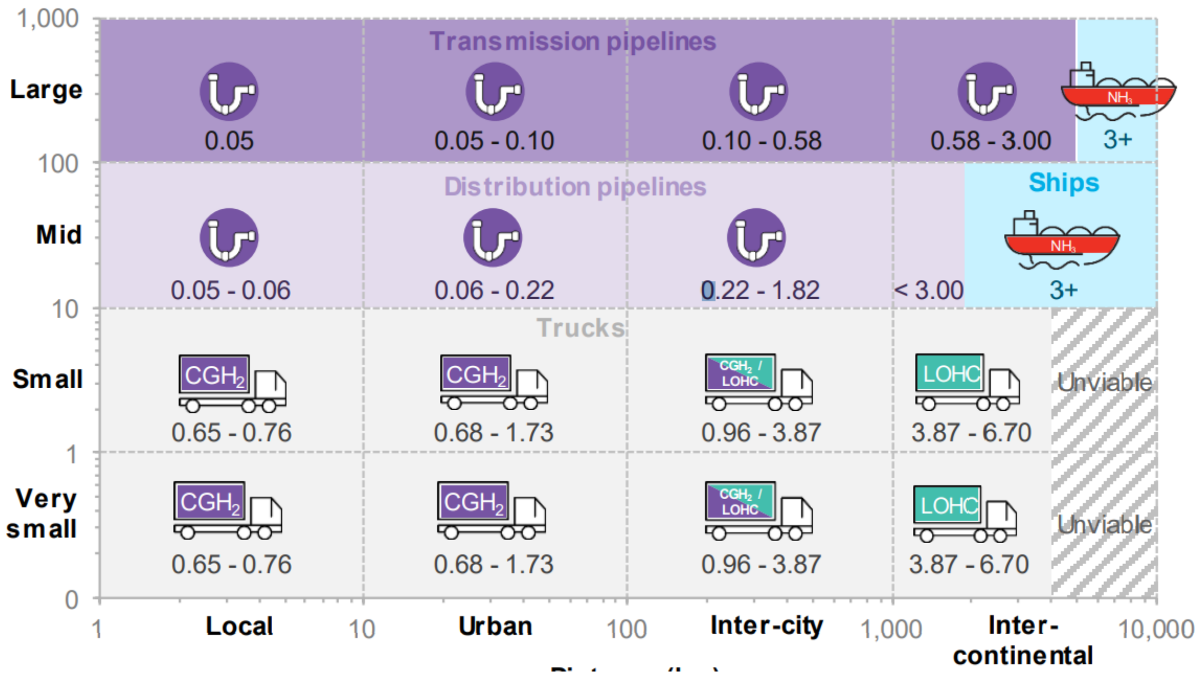


Figure 25. Transport options and costs for hydrogen and its derivatives based on distance and volume in $/kg; (Bloomberg New Energy Finance, Hitachi Energy; 2019)

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

Hydrogen transport cost strongly depends on distance and quantity transported. For long distances, highly compressed and liquid hydrogen are cheaper, even though the overall efficiency becomes lower. The optimal H2 transport mode will vary by distance, terrain and end-use: no universal solution exists.

Furthermore, Hydrogen pipelines can be cheaper than electricity transmission lines.

Exhibit 12: Overview of distribution options

<0.1 USD/kg | 0.1–1 USD/kg | 1–2 USD/kg | >2 USD/kg

		Costs				
		Distribution		Transmission		
		0–50 km	51–100 km	101–500 km	>1,000 km	>5,000 km
Pipelines[1]	Retrofitted	City grid	Regional distribution pipelines	Onshore transmission pipelines	Onshore/Subsea transmission pipelines	N/A
	New	City grid	Regional distribution pipelines	Onshore transmission pipelines	Onshore/Subsea transmission pipelines	N/A
Shipping	LH_2	N/A	N/A	N/A	LH_2 ship	LH_2 ship
	NH_3[2]	N/A	N/A	N/A	NH_3 ship	NH_3 ship
Trucking	LOHC[2]	N/A	N/A	N/A	LOHC ship	LOHC ship
	LH_2 trucking	Distribution truck LH_2	Distribution truck LH_2	Distribution truck LH_2	N/A	N/A
	Gaseous trucking	Distribution truck CH_2[3]	Distribution truck CH_2[3]	Distribution truck CH_2[3]	N/A	N/A

1. Assuming high utilization
2. Including reconversion to H_2; LOHC cost dependent on benefits for last mile distribution and storage
3. Compressed gaseous hydrogen

Figure 26. Logistic options for hydrogen (Source: Hydrogen Council)

A.4.5 Blending hydrogen into methane/natural gas

Without a hydrogen network, blending of hydrogen into the methane grid can be a transitional solution. However, blending reduces the value of the hydrogen related to economics and efficiency. Furthermore, the blended product, considering the decarbonization target of using the hydrogen vector, can only be used for thermal purposes (burning fuel)[16]. Indeed, in case pure hydrogen is needed, it has to be separated from methane with high effort (Figure 27).

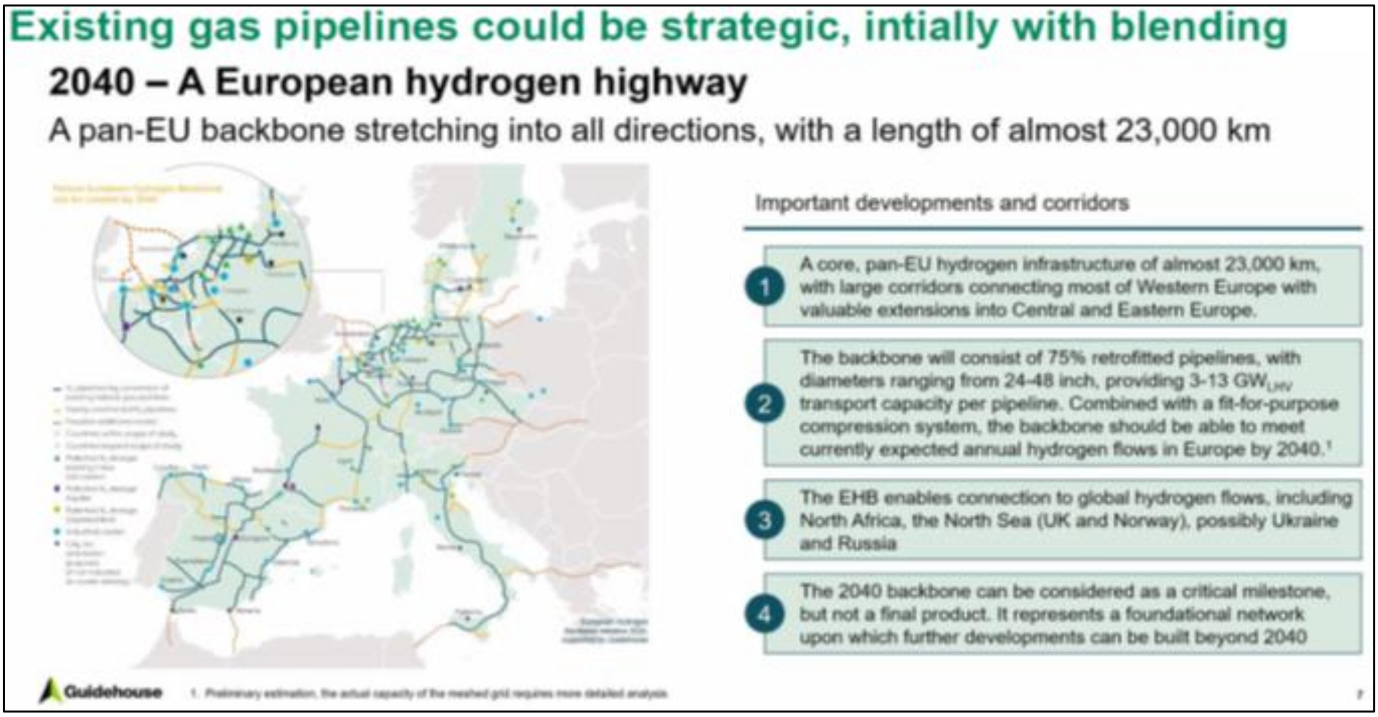


Figure 27. European gas pipelines re-purposing (Source: Gas for Climate)

Technically, blending is possible to a certain threshold that is under discussion in the moment. As it changes the gas quality, it has to be carefully considered on the one hand for quality-sensitive end-use applications and on the other hand for the infrastructure (gas network and storages). Therefore hydrogen should be integrated in a hydrogen network first, if possible.

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 blend with a 30% of hydrogen with 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 kind of fuel[17].

A recent study (October 2021) "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 can be reused for H2 and that onshore, close to 70% of the pipeline total length can be reused considering the current state of knowledge/standards. The remaining length of the pipelines is promising for reuse but would require more testing and/or 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

[16] Solid Oxide Fuel Cells can convert gas mixtures into electricity. They can also operate in reverse mode. Though not fully commercial in large scale, they are available in smaller scale and upscaling is taking rapid steps.

[17] IEA, *The Future of Hydrogen. Seizing Today's Opportunities*, Report prepared by the IEA for the G20, Japan, Juna 2019,

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%.

A.4.6 Hydrogen storage

(Green) 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 species.

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 H2 are still being studied today.

Currently there are different ways of storing H2. Alongside the more classic and widespread systems such as compressed gas and liquid gas, there are new techniques still under study such as chemical absorption / transformation (metal hydrides, ammonia, hydrocarbons) or physics (carbon nanotubes).

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

Physical/Compression methods:

- Compressed hydrogen gas (CGH2) at pressures from 50 bar up to 1000 bar.
- Liquefied hydrogen (LH2) at temperature of -253 °C. Liquefied hydrogen has a higher density energy than at gaseous state but required 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 (CcH2). The advantage of this technique is the higher energy density compared to the compressed hydrogen but, as mentioned, cooling process requires an additional important supply of energy.
- Liquid / solid mixture of hydrogen (Slush Hydrogen - SH2). The slush hydrogen 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 are currently the most mature and most used techniques in the sector typically through geological storage.

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.

Methods based on materials:

- Metal hydrides. Molecular hydrogen is first absorbed on the metal surface and then incorporated in elemental form (H) into the metal lattice with heat emission; then it can be released from the metal lattice by providing heat.
- Liquid hydrogen carriers (Liquid Organic Hydrogen Carriers - LOHC). LOHCs are chemical compounds with high hydrogen absorption capacity as the carbazole derivative N-ethylcarbazole as well as toluene.
- Surface storage systems (sorbents). Hydrogen can be stored by adsorption on materials with specific high surface areas.

Chemicals:

Converting hydrogen into decarbonized final products, such as SNG (synthetic methane) and ammonia (NH3) is an effective way to utilize also 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, 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 oil and exhaust gas reservoirs, salt caves or reservoirs in salt domes.

To date, operational experience for the storage of hydrogen in caves exists only in some areas of the USA (2 in TEXAS) and Europe (UK - Teesside). However, the most promising solution is the underground storage in depleted natural gas reservoirs or saline aquifers even if this solution is still little know and implemented due to the dynamics that could generated following the storage of hydrogen in a porous rock containing other fluids.

The salt caves are considered a valid option thanks to the holding capacity of the rock salt and the inert nature of the rock which guarantees the non-contamination of stored hydrogen. 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 (H2NG) 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 possible to use existing infrastructures while also avoiding the criticalities linked to the behavior of hydrogen could be to use hydrogen for methanogenesis i.e. the production of methane from green hydrogen and carbon dioxide and its accumulation in depleted fields.

It must be remembered that, compared to methane, hydrogen has 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, like CCGT in stand-by
- seasonal storage, where market seasonal consumption patterns are present, as it is currently for natural gas consumption (winter-summer); this can now be extended also to some generation patterns (seasonal winds, yearly sunshine cycle, etc.).

Large storage volumes are found in underground caverns or depleted gas reservoirs, but they are not widespread and not equally geographically distributed, so a dedicate 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 gris 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. With the assumed RES development scale and a significant saturation of these surpluses with electric cars, there will probably not be enough for hydrogen to play a leading role in the economy in the coming years.

As indicated by ACER and CEER, it would be important to "Introduce a link between actual gas consumption and Member State storage capacity and other specificities such as LNG availability or demand seasonality when setting filling requirements to ensure security of gas supply. For that purpose, regulators recommend conducting an analysis of the role of storage in order to identify the most appropriate measures for the different situations that may be encountered across the EU. Once the measures are in place, EU-wide monitoring of storage filling levels and of the prices paid for those fillings will need to be put in place. This will allow policymakers to learn from the current experience, identify best practices, and achieve good results at a much lower cost for consumers for next year's filling seasons. Furthermore, existing national rules and practices that have enabled efficient use and development of storage capacities should be preserved and may be promoted within the regional risk groups."

Appendix 2

Hydrogen use case on MV/LV

Figure 28 presents the power system in a symbolic way, which can be treated as a repeatedly closed system for the transmission network and distribution network at 110 kV. At selected nodes, conventional (EK) and wind energy sources (onshore LFW and offshore MFW) are connected. The prosumer solar farm is connected at a low voltage level and is not presented in the figure. It can be expected that the production of hydrogen on a large scale will take place in electrolyser systems with a capacity of up to several hundred megawatts (in the EU hydrogen strategy the standard is a 100 MW module unit[18]) connected to the transmission network (marked with the letter E). Feeding power from large groupings of offshore farms and onshore farms to the grid, under some circumstances - grid architecture) might create the risk of overloading (marked red) high-voltage lines. It is worth mention the issue of the location of electrolysers. It may be imposed by gas infrastructure conditions and environmental restrictions. It may also result from the location of hydrogen storage sites (salt caverns). It should be emphasized that even the location of the electrolysers distant from the RES generation sites enables their interaction with these sources, in particular, full-power operation in order to manage the surplus generation and standstill in conditions of high demand. It is already fully possible to create appropriate group control systems for "RES - electrolysers" systems. Of course, it is possible to connect the RES source and the electrolyser installation within one network infrastructure, and moreover, introduce such a control system that strictly controls the level of power flowing into the system and possibly from the system. Such a solution can bring a number of technical (overload elimination) and economic benefits [19].

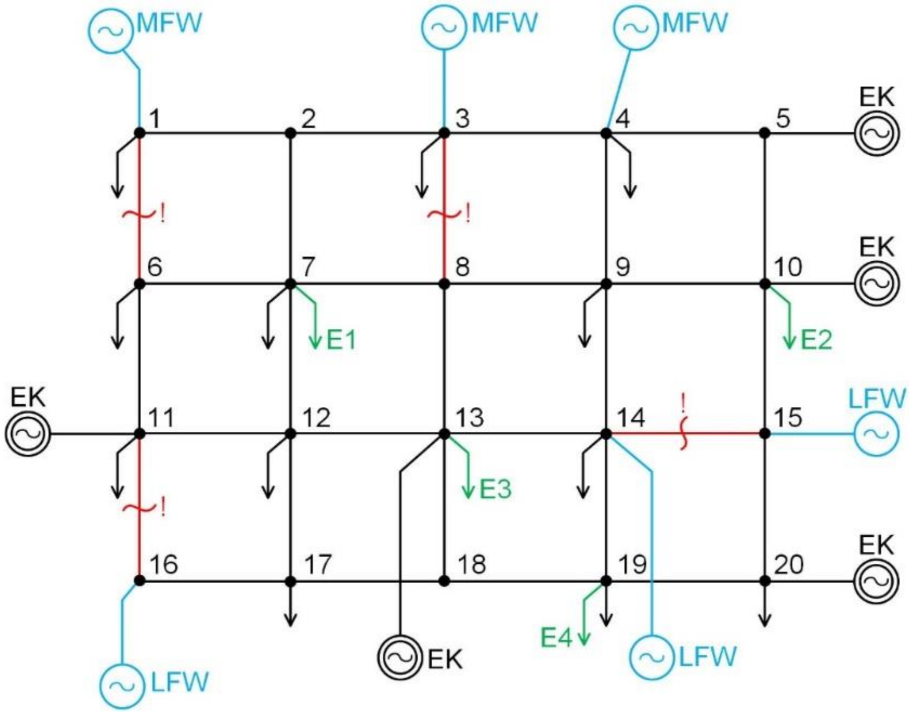


Figure 28. Illustrative structure of closed electricity system with conventional generation, onshore and offshore wind energy and electrolysers integrated with wind farms; visible hydrogen infrastructure (networks, storage), with turbines (TG) performing G2P functions (Source: DISE Energy, PSEW, "Zielony wodór z OZE w Polsce. Wykorzystanie energetyki)

[18] European Commission, Communication From The Commission To The European Parliament, The Council, The European Economic And Social Committee And The Committee Of The Regions. A hydrogen strategy for a climate-neutral Europe, Brussels, 8.07.2020. COM (2020) 301 final.

[19] DISE Energy, PSEW, "Zielony wodór z OZE w Polsce. Wykorzystanie energetyki wiatrowej i PV do produkcji zielonego wodoru jako szansa na realizację założeń Polityki Klimatyczno-Energetycznej UE w Polsce", December 2021, p. 103 *wiatrowej i PV do produkcji zielonego wodoru jako szansa na realizację założeń Polityki Klimatyczno-Energetycznej UE w Polsce*", December 2021, p. 103).

The development of hydrogen production in a large-scale system, which will be of great importance for ensuring the balanced operation of the power system in the future, does not eliminate the development of hydrogen production from electrolysers connected to the distribution network. This segment will develop as a local production market including 100 kW, 0.5 MW, 2 MW and 10 MW electrolysers. In addition to being significant for the development of the broadly understood hydrogen economy, it may also contribute to the improvement of grid operating conditions at the medium voltage level. The concept of the voltage regulation system in the medium voltage grid, in which renewable energy sources integrated with electrolysers work together with a traditional transformer equipped with a tap changer under load, is presented in the figure below.

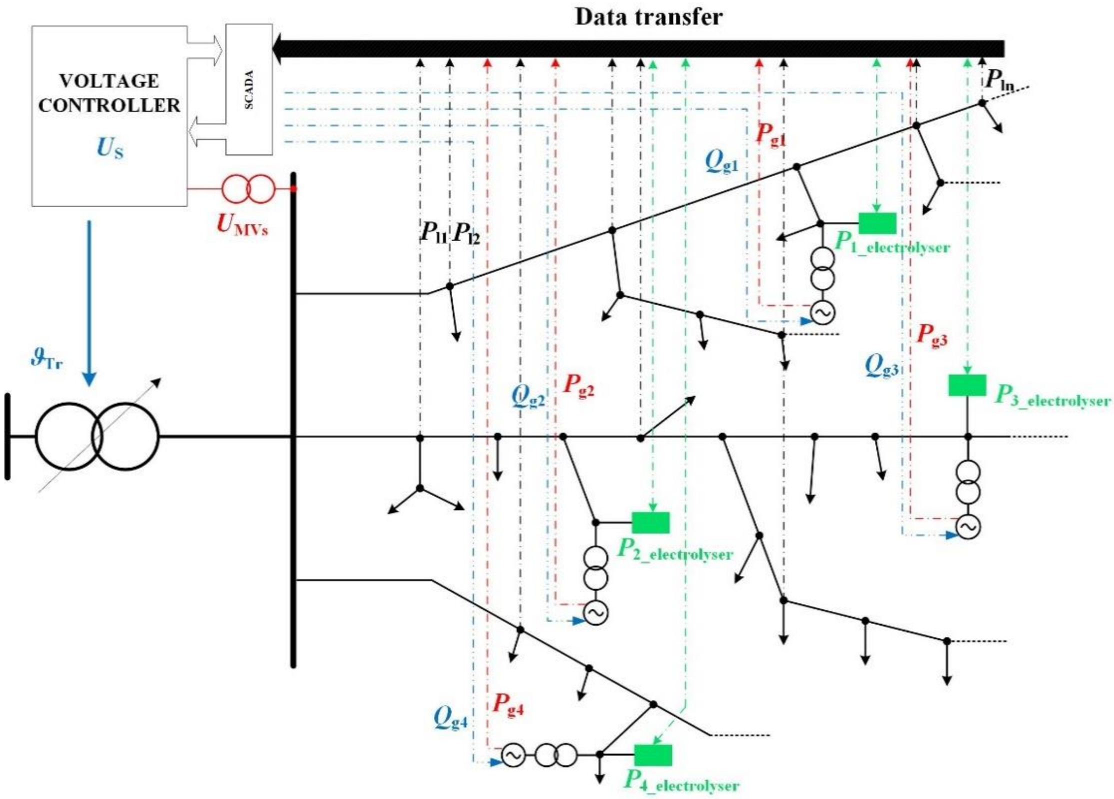


Figure 29. Concept of the voltage regulation system in the MV network with connected renewable energy sources, integrated with the power regulation of the electrolysers (Source: P. Pijarski, P. Kacejko, Voltage Optimization in MV Network with Distributed Generation Using Power Consumption Control in Electrolysis Installations, „Energies" 2021, 4 (14).

As a result of the generated power variety, the voltage values in the network also change, deteriorating the quality of power supply to other consumers (Figure 30). Controlling the power of local electrolysers by means of a regulator cooperating with a transformer significantly improves the quality of this voltage and reduces its changes caused by local wind generation (DISE Energy, PSE, 2021).

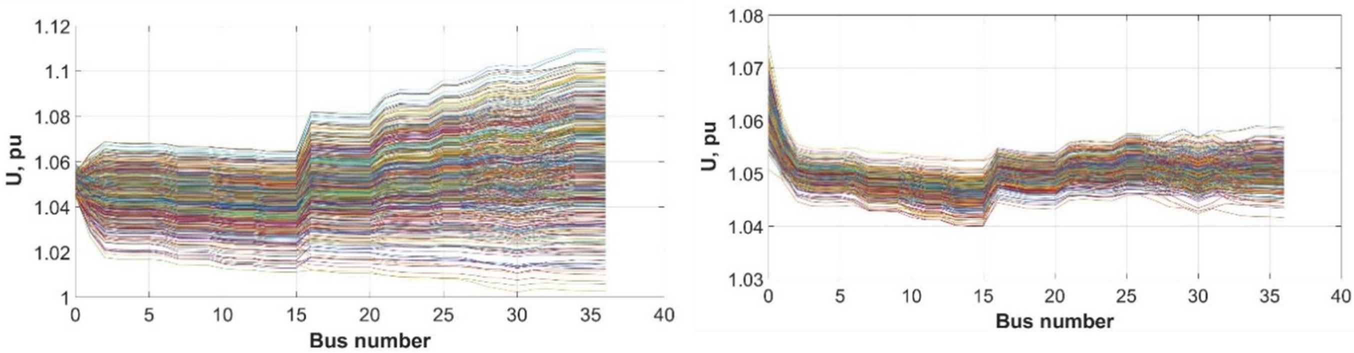


Figure 30. The effect of power control of electrolysers connected to the MV grid, reducing voltage changes in grid nodes caused by RES generation[20]

[20] P. Pijarski, P. Kacejko, Voltage Optimization in MV Network with Distributed Generation Using Power Consumption Control in Electrolysis Installations, „Energies" 2021, 4(14).

The use of electrolysers in voltage stabilization is not the only possible application. Other applications include their use for power stabilization or smoothing, or ramping. In these cases, the electrolysers are used as regulated loads of variable power, storing energy in hydrogen. These actions lead to a certain reduction of the output power of renewable energy sources, although they give it the expected shape, thus supporting the operation of the power system.

In the case of single wind turbines, additional generation of power could be provided by fuel cells powered by the stored hydrogen (Figure 31).

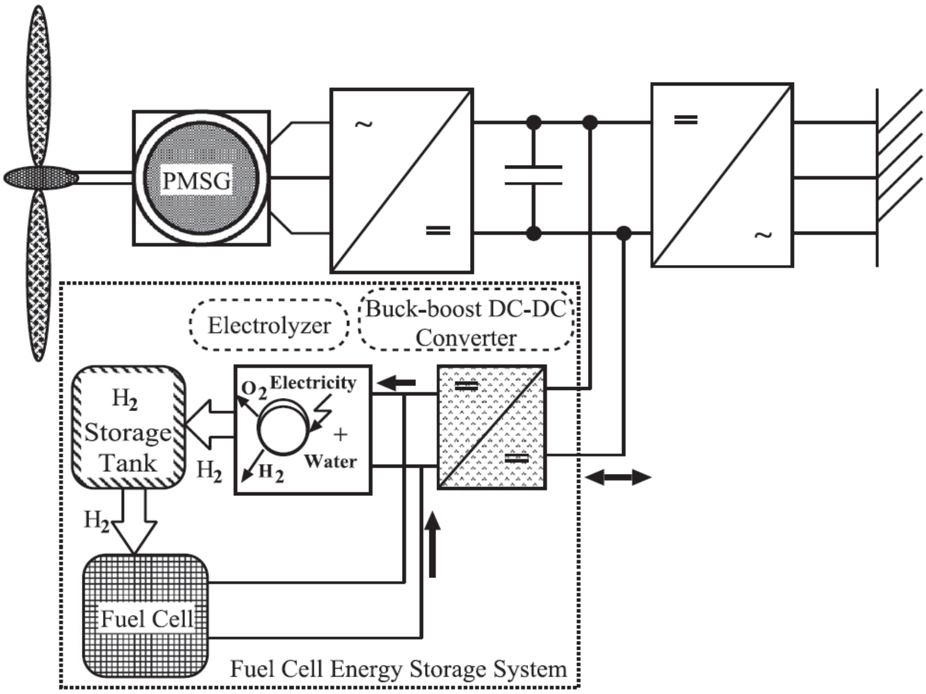


Figure 31. Hypothetical system of using a hydrogen storage and a fuel cell to "smooth" the output waveform of a wind turbine[21]

From the market point of view, the importance of hydrogen production for the power system should be seen from the perspective of the possibility of providing services to network operators. These services can be classified into several groups (Figure 32):

- ancillary services provided to the transmission or distribution system operator,
- flexibility services (understood as support for the MV and LV networks) provided to distribution operators,
- an alternative for reduction the RES production at the operator's request,
- an alternative for RES curtailment at the operator's request.

[21] A.M. Howlader, N. Urasaki, A. Yona, T. Senjyu, A.Y. Saber, *A review of output power smoothing methods for wind energy conversion systems*, „Renewable and Sustainable Energy Reviews"2013, 26

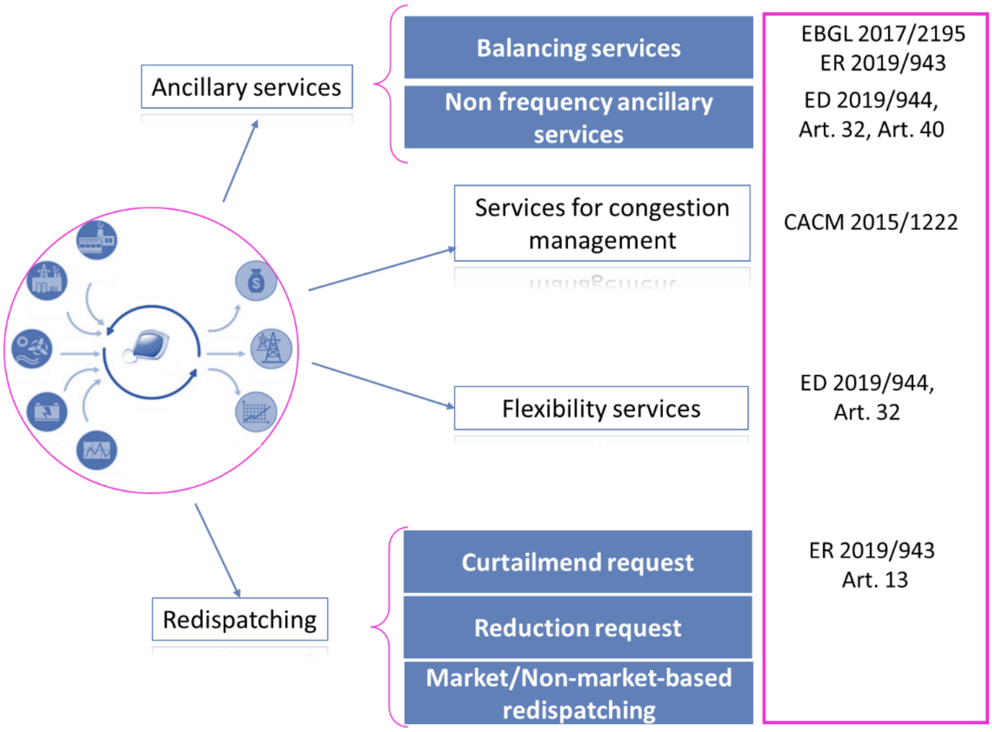


Figure 32. Possibilities of using hydrogen for the purposes of transmission and distribution of the power system (Source: DISE Energy, PSEW, "Zielony wodór z OZE w Polsce. Wykorzystanie energetyki wiatrowej i PV do produkcji zielonego wodoru jako szansa na realizację założeń Polityki Klimatyczno-Energetycznej UE w Polsce", December 2021, p 111),

The possibilities of involving electrolysers in the management of the power system, listed in the figure, present how widely the production of green hydrogen can be used in the future. The aforementioned services constitute a range of additional tools for both electricity grid operators and entities involved in the commercial production of hydrogen. With optimal management of the location, configuration with other devices and the operation of electrolysers, there could be great potential to achieve many benefits for the parties involved as well as to accelerate the decarbonisation of the economy.

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