GIE Position on Blending Hydrogen into Existing Gas Infrastructure

1 Executive Summary

- Blending is an **effective and cost-efficient transitional solution for certain EU regions**, whilst other regions will move directly to dedicated H_2 transport without using blending.
- The **convenience of blending in a given Member State depends on the national circumstances** linked to its gas infrastructure topology (existence of parallel gas systems such as L-gas/H-gas, abundance of gas infrastructure, etc.), the industrial and population density, geographical size, distance between H_2 production and consumption centres, etc.
- **Blending has multiple advantages as well as several challenges**, **which can be overcome** with the right policy, regulatory and technical decisions.
- In the absence of dedicated H_2 infrastructure and/or consumption centres located nearby, the existing gas infrastructure gives injected H_2 the access to an EU integrated gas market. Blending is a **stepwise approach to stimulate H_2 production in the short and medium term**, until dedicated H_2 transport infrastructure becomes more economic in those regions.
- **Retrofitting costs** have to be assessed. They **depend on the maximum desired percentage of H_2 to be handled**. Up to a certain hydrogen limit, the retrofitting costs are acceptable. However, when handling H_2 percentages equal or above a certain threshold[1], the retrofitting costs increase substantially, and it might be more economically attractive to repurpose the gas pipeline.
- **Underground gas storages** will continue providing flexibility and **playing a role** in facilitating H_2 blending. The **consequences of the H_2 admixtures**, especially on the integrity of the storage facility, are **to be carefully assessed** case by case before handling mixtures with more than 2% (volume) hydrogen.
- **Deblending[2] is a promising technology** which deserves additional R&D efforts and which can significantly help to better manage the share of H_2 within the gas system.
- **GIE recommends setting up a sound and clear regulatory framework for blending/deblending hydrogen into gas infrastructure**, which favours the introduction of advanced gas quality handling tools, more R&D efforts and a **GO system**. The framework should **recognise and remunerate duly justified investments** by infrastructure operators, and the recovery of **gas quality & hydrogen handling costs**, including the costs incurred by gas infrastructure operators when dealing with hydrogen sensitive consumers.
- **Interoperability should be guaranteed at IPs** to preserve an integrated gas market. A common **EU minimum H_2 admissible threshold** should be considered to facilitate cross-border flows of mixtures. **The Gas Decarbonisation Package could design the process to fix such minimum amongst the concerned TSOs and NRAs,** taking into account interest from relevant stakeholders (e.g. end-users, non-EU TSOs, etc.). **TSOs** should be **allowed to bilaterally agree on higher acceptable H_2 shares** at their respective IPs without an EU cap.
- Gas infrastructure operators could develop their own **blending roadmaps** which would include the adaptations required in their systems to reach their blending ambitions. **Coordination among infrastructure operators**, at national/EU level, **remains essential**.

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[1] Some operators see this threshold around 20% H_2 share (volume), whilst others refer to the 2-10% H_2 share (volume).

[2] Separation of Hydrogen from H_2/natural gas mixtures

2 Introduction

The European Green Deal has put the EU on a path to become the first climate neutral continent by 2050. This goal will be achieved through the deep decarbonisation of all sectors of our economy. Hydrogen will be an important solution to meet the 2050 climate neutrality goals enshrined in the European Green Deal.

Certainly, electrification is one of the trends in the ongoing energy transition. Due to the recent exponential growth curve and associated cost reductions, solar and wind power in good locations are now often the least cost option. However, electricity has limitations in long-range energy transport and large scale/long-term energy storage. It also has concrete limitations in the transport sector (long-range HDV, maritime, etc.) and in meeting energy needs of industrial processes requiring high temperature heat, chemicals feedstock, etc. Moreover, a high degree of electrification brings questions on costs, security of supply and resilience which need to be answered beforehand.

Due to their geographical characteristics and population density, a large number of EU Member States will not be able to satisfy all their renewable energy needs. This circumstance, together with the fact that the best locations for renewable energy production are usually far from consumption centres, implies that a large part of renewable energy will have to be imported and/or traded from long distance, often across borders.

Power-to-Gas was initially thought of as a way to alleviate the electricity grid constraints and curtailment but, today, the modern concept of power to gas is broader. It implies the development of an EU-wide hydrogen economy where hydrogen becomes an EU-wide traded cost-competitive commodity. Hydrogen will act as an energy vector, with high energy density, easy to be transported over long distances and stored flexibly in large quantities for long periods of time (e.g. seasonal storage), in a cost-efficient way and connecting production and demand centres. In this context, renewable and low-carbon hydrogen will be especially effective in decarbonising current grey hydrogen use in the petrochemical and fertiliser industries. Hydrogen has a strong potential to be used in particular in those sectors which are hard to electrify due to, for instance, the lack of infrastructure or other feasible technological solutions, or simply because electrification is not economically competitive.

The EU Hydrogen Strategy has set the strategic objective to install at least 6 GW of renewable hydrogen electrolyser in the EU and the production of up to 1 million tonnes of renewable hydrogen by 2024. Moreover, the Strategy has the ambition of having at least 40 GW of renewable hydrogen electrolysers and the production of up to 10 million tonnes of renewable hydrogen in the EU by 2030. Low-carbon hydrogen is also expected to be needed in the short and medium term. In the EU's strategic long-term vision[3] for a climate-neutral economy, the share of hydrogen in Europe's energy mix is projected to grow from the currently less than 2% to 13-14% by 2050.

The hydrogen ecosystem in Europe is likely to develop through a gradual trajectory, at different speeds and with different solutions across sectors and across regions. The infrastructure needs for

[3] EC's 2050 Long-term Strategy (link)

transporting hydrogen will also evolve at different speeds and with different solutions, together with the development of production and supply centres to be connected.

When it comes to hydrogen being transported by pipelines, three solutions are identified:

1) Retrofitting[4]
2) Repurposing[5]
3) Construction of new dedicated hydrogen infrastructure[6]

The three hydrogen deployment options can even co-exist and co-evolve where needed.

In certain European regions the retrofitting option (i.e. hydrogen blending) will occur on a transitional basis on the way to achieve the common long-term goal of an EU-wide hydrogen dedicated network system.

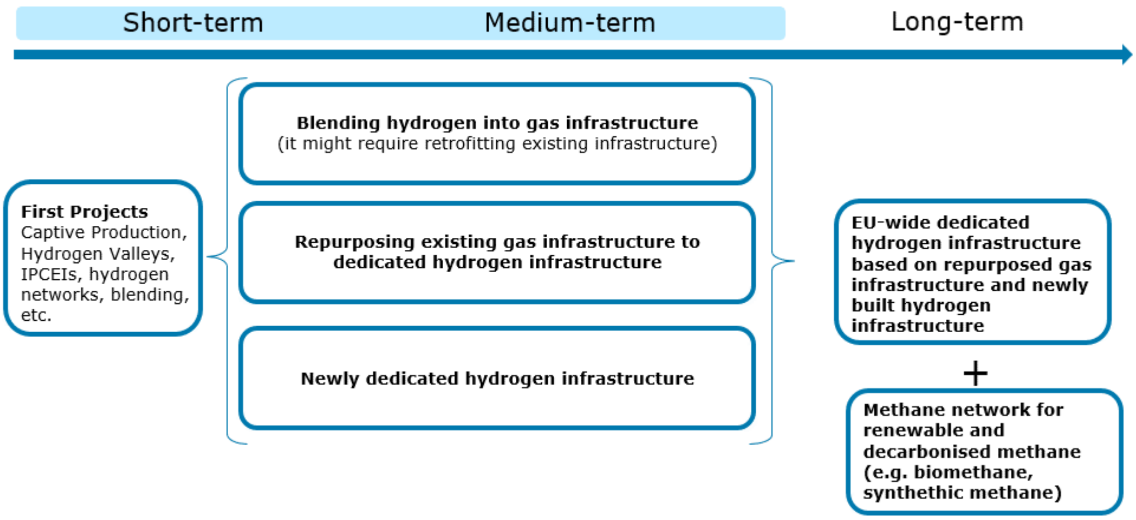

Figure 1: Foreseen evolution of hydrogen-related and gas infrastructure

3 What is Hydrogen Blending?

Hydrogen blending is the injection of a share of hydrogen into the existing gas infrastructure. It offers the following services:

1. **Transport and Storage of Hydrogen**, allowing injection of hydrogen (surplus) into gas infrastructures and lowering the cost of linking demand and supply. When linking blending and deblending technologies, then gas becomes a hydrogen carrier.

2. **Decarbonisation Tool**: a step-by-step approach to enable those customers connected to gas networks with mixtures, to gain access to hydrogen and progressively decarbonise their energy consumption.

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[4] Retrofitting refers to modifications/adaptations of the gas infrastructure that allow injection of certain amounts of hydrogen up to a technically-sound threshold of H_2/CH_4 mixture (i.e. hydrogen blending)

[5] Repurposing implies converting an existing natural gas pipeline infrastructure into a dedicated hydrogen pipeline infrastructure. In the framework of gas asset readiness, a repurposed natural gas pipeline would be ready to transport H_2/CH_4 mixtures, capable of reaching up to a 100% hydrogen flow stream.

[6] This option implies the construction of dedicated Hydrogen infrastructure (i.e. hydrogen pipelines, hydrogen underground storages, etc.) from scratch.

The maximum allowable hydrogen concentration in the system depends mainly on a number of characteristics linked to each specific gas pipeline (material, structure, etc.) and its related equipment (valves, compressor stations, chromatographs, etc.). The way to handle technical specificities linked to storage facilities and end-users should also be taken into account.

According to the current literature[7], the injection of 2% of hydrogen in volumetric terms is possible without any adaptation other than the installation of required gas chromatographs for the measurement.

However, widespread knowledge to date indicates that certain blending percentages (e. g. 2 % – 10 % in volumetric terms)[8] are technically feasible with few adaptations in some Member States. Although additional tests are needed, some transmission operators consider 20% H_2 share[9] in volume to be the upper bound in particular due to the hardware requirements for downstream users to be adapted beyond this point. As regards to technical regulation, blending of hydrogen is already explicitly recognised by some Member States[10].

According to ACER[11], current research suggests that most applications, with the exception of industrial consumers using natural gas as raw material or those non-tolerant to H_2/gas mixtures exceeding certain low percentages, could be adapted to work with hydrogen and methane blends with a 15-20% hydrogen content. Nevertheless, the adaptations needed to reach these targets can be quite significant in terms of infrastructure and end-user applications. Beyond that threshold, any increase in hydrogen share requires further checks and investigations and would likely require significant adaptations or even replacement of infrastructure as well as end-user appliances. Hence, any notion about the gradual increase of hydrogen concentration in some existing gas networks is considered only up to a certain threshold, beyond which a complete repurposing to a dedicated hydrogen network system may prove to be more economical[12]. Nevertheless, hydrogen injection into the gas grid is highly case-specific, subject to the natural gas quality and local regulations.

Recent EU policy developments, including the revised TEN-E regulation, also recognise the transitional role of hydrogen blending in the transformation of the European energy system.

[7] Marcogaz presentation

[8] ENTSOG/GIE/Hydrogen Europe: *"How to transport and store Hydrogen – Facts and Figures"* (link)

[9] Some operators see this threshold around 20% H2 share (volume), whilst others refer to the range 10%-20% H_2 share (volume).

[10] e.g. Portugal

[11] ACER: *"Possible regulation of hydrogen networks"* (link)

[12] Source: ACER

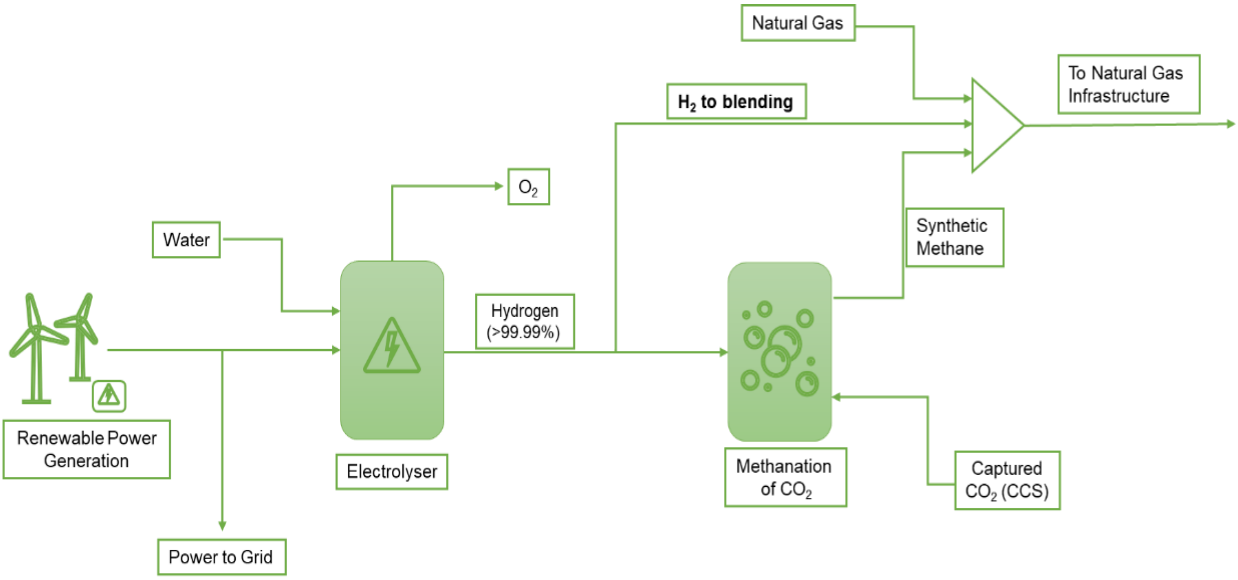

Figure 2: Concept diagram on hydrogen blending into the gas grid

4 Advantages of Hydrogen Blending

Hydrogen blending has multiple advantages such as:

- **A Quick and Affordable First Step for the Hydrogen Economy**

  In most locations in Europe, hydrogen production and consumption will only grow gradually. Furthermore, the best locations for optimal production of renewable electricity are usually in remote areas.

  In regions where blending is the preferred option, initial investors in hydrogen production facilities face the risk of (1) a lack of an immediately available dedicated hydrogen infrastructure in place and (2) no nearby consumption centre of hydrogen. The gas grid has the advantage of an extensive capillary network, giving access to an integrated EU gas market and representing a secured offtake for hydrogen production. The injection of H_2 into the existing gas grid could provide a quick and affordable transitional solution to handle these risks whilst they are not addressed. The lower investor risk will have a significant positive impact on the growth of hydrogen production in the short-term.

  Mixtures of H_2/natural gas could facilitate initial H_2 production deployment allowing for a gradual penetration of hydrogen into the gas system, in an orderly manner that would permit policy makers and system operators to take lessons and face challenges linked to the early stages of hydrogen market development.

- **Allows Certain European Regions to Use an Affordable Stepwise Approach to Achieve an EU-wide Dedicated Hydrogen Network**

  The convenience of blending in a given region depends very much on the national/local circumstances and that is why blending is understood as an option for some EU regions. In these EU regions usually the business case for the development of hydrogen pipelines (either new ones or repurposed from natural gas) in the short/medium term is uncertain. These regions can be characterised for being:

  - without parallel or duplicated networks (e.g. H-gas and L-gas networks, imports/transportation routes with several pipelines in parallel);

- without (potentially) available gas infrastructure capacity which can be easily repurposed to hydrogen in the short/medium-term;
- or with a large geographical size and/or relatively low industrial density.

In these regions, H_2/CH_4 mixtures usually can represent, from a cost perspective, a reasonable and affordable initial stepwise approach which does not require very large capital investments upfront. Blending allows for building-up hydrogen production capacities, gaining experience and knowledge in transporting and storing hydrogen, and helps to achieve a positive business case in the medium/long term for the repurposing of the existing gas grid and the construction of newly built hydrogen infrastructure.

- **Fast and Cheap GHG Emissions Reductions in the short/medium term**

Hydrogen blending is a potential decarbonisation tool that supplements other initiatives rather than competes with them. According to IRENA[13], a 20% volumetric renewable hydrogen share in natural gas could reduce CO_2 emissions by 7% per energy unit. In an initial period, and given the immediate availability of gas infrastructure, injecting hydrogen admixtures in the existing gas grid can achieve fast GHG emissions reduction at a low cost.

In the absence of dedicated hydrogen infrastructure, hydrogen blending into existing gas grids would also avoid GHG emissions associated with the transportation of that hydrogen by means of more carbon intensive transport options such as trucks, ships, etc.

- **Sector Coupling**

When it comes to sector coupling between electricity and gas via Power-to-Gas (P2G) plants, such as electrolysers and pyrolysis plants, and where dedicated hydrogen storage is not possible/available, hydrogen blending is an option which provides access to large storage capacities in the existing gas infrastructure system. In this way, blending can contribute to enhance system-wide resilience by integrating surplus intermittent renewable electricity, reducing power network congestion and providing short-term flexibility and large/seasonal energy storage.

- **Decarbonisation Opportunity Available to all Gas Consumers**

The injection of hydrogen into the gas grid provides the option of having access to renewable and low-carbon energy, up to a certain level, for all gas consumers connected to the gas network. It could also allow for further commercial and regulatory developments associated to renewable and low-carbon gases, such as specific tariffs, guarantees of origin and in general support growing consumer's appetite for these gases.

- **Relevant Capacities Available**

The European gas grid has more than 2 million[14] kilometres of gas distribution networks, and more than 200 000 km[15] of high- pressure pipelines. It transports around 5 000 TWh/year, while underground gas storages in the EU are able to store almost 1 200 TWh of energy. Given the large capacity of the gas system, even injecting relatively low hydrogen

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[13] IRENA: *"Green Hydrogen Supply"* (2021) (link)
[14] https://www.acer.europa.eu/gas-factsheet
[15] https://www.acer.europa.eu/gas-factsheet

shares could enable the absorption of significant quantities of renewable and low-carbon energy in absolute terms.

- **Allows for higher load factor in electrolysers**

When hydrogen production plants (e.g. electrolysers) are constrained on the consumption side, off-takers are not able to consume all the hydrogen the electrolysers are able to produce. In order to allow for higher load factors, hydrogen production plants require a "buffering" service to deal with demand fluctuations and store excess hydrogen relative to demand. This "buffering" service can be provided via dedicated H_2 pipelines and storage. However, in some regions blending could fulfil this role.

By making use of the large transportation and storage capacity offered by the gas grid, hydrogen production plants are not obliged to follow consumption patterns of directly connected (industrial) consumers. Therefore, the hydrogen production plants can inject hydrogen in large quantities since the gas system through its linepack and, where possible, its underground gas storages, acts as an intermediate "buffer".

- **Deblending is technically possible**

The R&D work[16] with separation technologies (e.g. membranes) is ongoing and proving that hydrogen can be deblended from a natural gas flow stream, enabling the possibility of handling gas quality and hydrogen purity for end consumers. Deblending technology could provide future options to managing greater shares of H_2/CH_4 blends, underpinning the use of blending, and acting as a potential tool which Member States can use to decarbonise their gas system. Finally, separation technologies may present solutions to protect H_2 sensitive consumers.

- **Enabling usage of excess biogenic CO_2 to produce and inject e-methane**

By allowing for a certain share of hydrogen to be blended into the existing gas grid, biogenic CO_2, e.g. from the upgrading process of a biomethane plant, can be used to produce e-methane, which can itself be injected and transported in the same gas grid together with the biomethane.

The production of e-methane always leaves an amount of hydrogen, depending on the process facility, mixed into the e-methane stream. Therefore, to enable the production and injection of e-methane into the natural gas system, it is also necessary to allow for a certain (low) level for hydrogen share into the gas system. On this way biomethane plants can then create value for CO_2 which would be otherwise released into the atmosphere. Moreover, biomethane plants become more reliant on dedicated H_2 supplies, thus promoting further the development of the hydrogen economy.

5 Hydrogen Blending Challenges to be addressed

- **Adaptation of the Existing Networks (retrofitting)**

Depending on the share of hydrogen to be injected, the gas network might need concrete retrofitting actions. The number and size of the required modifications are dependent on multiple aspects related to characteristics of concrete segments of the gas system, such as

[16] E.g.: Costain study (link), HyNTS (Hydrogen Injection into the NTS and Hydrogen Deblending by National Grid)

compressor stations, pipeline material, metering equipment (chromatographs), valves, tanks, etc.

In the case of compressor stations, hydrogen has a significantly lower molar weight than natural gas, which is a parameter for the commonly used centrifugal compressors. Different compressor models react in different ways to hydrogen blends, although usually they are not fully optimised for blends. For example, SIEMENS[17] states that, when transported, a hydrogen share below 10 % only leads to minor changes of existing compressors, while a share of above 40 % requires its replacement. Compressors themselves are usually driven by gas turbines. Many new and recently installed gas turbines show strong resilience towards blends. Some gas turbines would however require modifications, and equipment manufacturers are working to offer adequate solutions in the short-term. In any case, it should be also noted that more and more e-compressors are being installed across Europe.

Hydrogen embrittlement is another aspect to be assessed, which entails a metal's loss of ductility and the reduction of load bearing capability due to the absorption of hydrogen atoms or molecules by the metal. The result of hydrogen embrittlement is that components crack and fracture at stresses less than the yield strength of the metal. Solutions include the identification of piping hydrogen toughness, the application of "inner coating" to chemically protect the steel wall, monitoring of pipes, development of integrity plans and safety coefficients, changes in the transmission conditions, etc. The optimal solution varies per pipeline, as it depends on several criteria including pipeline transport capacity requirements, status of existing pipelines and trade-offs between capital and operating expenditure. Nonetheless it is known that not all materials are susceptible to embrittlement and, in any case, there are always technical solutions to avoid this problem. Carbon steel (metallic) pipelines transporting 100 % H_2 have been operating for many years without any embrittlement problem.

The retrofitting of the network brings challenges which can be technically solved in an affordable way for hydrogen shares up to a certain limit. Existing studies show that, generally, at relatively low hydrogen concentrations (up to 10–20 % in volume), blending may not require major investment or modification to the infrastructure and can be done in a safe manner.[18]

Beyond that threshold (10%-20% in volume), any increase in hydrogen share requires first of all further checks and investigations (within transmission networks) and would likely require infrastructure as well as significant adaptations or even replacement of end-user appliances. Hence, any notion about the gradual increase of hydrogen concentration in existing gas networks, is considered up until a certain turning point, when a complete transition to dedicated hydrogen networks may prove to be more economical.

- **Ensuring EU-wide Interoperability (Gas Quality handling at IPs)**

Since the characteristics of H_2 differ from natural gas, the introduction of H_2 into the natural gas grids will extend the role that TSOs play in gas quality management, adding new tasks and responsibilities, and determining the offer of additional gas quality services. Building on their large experience and competences in the field of gas quality, gas network operators will undergo an evolution from their current role of natural gas transportation to one which

[17] Siemens Energy: "Reusing gas infrastructure for hydrogen transportation" (link)

[18] According to IEA (2015); DNV-GL (2017); NREL (2013); National Research Council Canada (2017);

involves managing the injection and offtake of more diverse gas qualities. In this new situation, not only the gas composition will play a role, but also the allowed variations in gas quality.

It is crucial to ensure that the injection of different gases does not undermine the existing interoperability of the EU gas infrastructure, which is central for the integrity of the internal market. Today, the different levels of hydrogen blending shares accepted across the EU show the need to work in order to enhance the future interoperability of gas networks (see figure below).

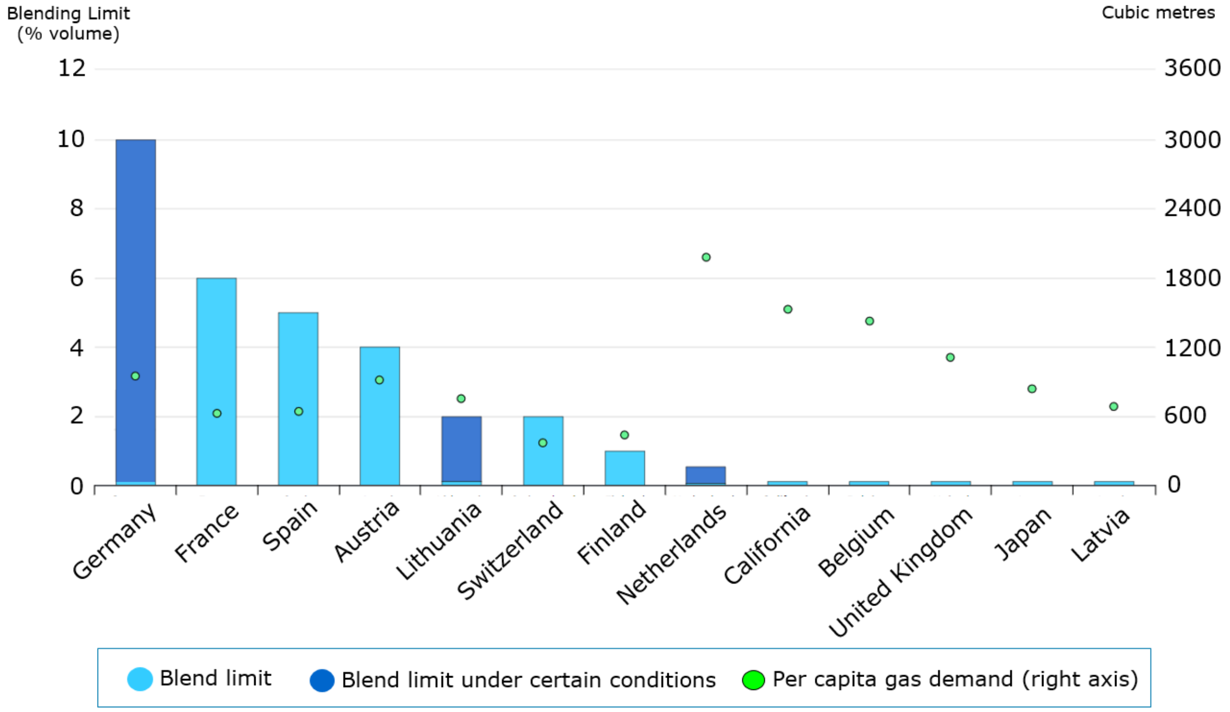

Figure 3: Limits on H_2 blending in natural gas networks and gas demand per capita in selected locations [19]

To safeguard the interoperability of the gas system, the European regulatory framework includes rules for gas quality issues in the Interoperability Network Code so that TSOs find agreements bilaterally concerning gas quality specifications and/or handling via negotiating their Interconnection agreements (IA). Consistently the injection of H_2 is only one of the parameters of the relevant IA. In order to avoid market fragmentation because of different hydrogen/natural gas mixture specifications, the future EU legislative framework should facilitate intra-EU cross-border trade of gas blends, foreseeing a number of interoperability measures at technical and commercial level. TSOs should be allowed to bilaterally agree on individual H_2 contents at their respective IPs in line with their technical and national regulatory requirements.

Within the framework of the future applicable EU legislation, a common EU-wide minimum H2 acceptability threshold should be considered to facilitate cross-border flows of H2. Provisions in the gas decarbonisation package should design the process to fix such minimum amongst the TSOs and NRAs concerned and the adjacent TSOs potentially

[19] Source: GIE and IEA Data and Statistics Charts, 2020 (link). The graph has been edited for clarity and readability. In the case of Germany, the realistic blending limit in Germany is about 0,1% according to the old and new G260. There are still ongoing discussions among German stakeholders about acceptable blends for end-users.

impacted. The process should also consider requirements of end-users and connected non-EU TSOs.

Moreover, the TSOs should have the flexibility to bilaterally negotiate the maximum share at their respective IPs, without any EU-wide maximum cap. When necessary, TSOs could involve NRAs (as it is currently the case via Article 15 of the Interoperability Network Code) if a restriction to cross-border trade is identified due to gas quality differences.

In principle, a TSO is expected to accept at the IPs a level of hydrogen share equal to the maximum hydrogen blending percentage recognised in its national framework (yet, currently in some Member States there is no national specification defined for H_2 mixtures). If in the future the H_2 limit or the H_2 share's variability in the Interconnection Agreements at IPs is above a national limit, there will be a need for implementing advanced gas quality handling tools (including smart metering, digitalisation, data analytics and deblending) to adjust the H_2 percentage to the limits agreed within the IA. Such investments by TSOs, duly justified, should be adequately recognised by the NRA and remunerated.

At IPs, the costs for deblending should be borne by the TSO that exceeds the H_2 limit of the Interconnection Agreement (as it is the case today) or by the TSO requiring stricter parameters compared to the common EU minimum standard (if any).

Lastly, TSOs, after consulting DSOs and SSOs, could collect and indicate (for informative purposes) the most attractive areas for H_2 injection from the grids' perspective in the national network development plans or in alternative publications depending on national preferences. To protect downstream assets or to safeguard injections of existing H_2 producers, TSOs must be able to reject H_2 injection points at unacceptable locations, if this is not technically or economically feasible, or to guarantee only conditional entry capacities (e.g., depending on the flow of base gas in the relevant pipeline). This coordination of H_2 injection points upfront would reduce the expenditures on gas quality mitigation measures.

- **Providing solutions for End-users not accepting mixtures H_2/CH_4 over certain H_2 percentage**

  Consumers of hydrogen admixtures are the same consumers connected today to gas networks, such as industries and users of domestic gas heating. While the majority of consumers are able to cope with relatively large percentages of hydrogen (i.e. 10-15%)[20], some end-users, however, do not tolerate admixtures over certain concentration levels and/or cannot cope with large and fast H_2 percentage fluctuations. Gas network operators should identify and collect information about the sensitive consumers (such as the quantity of sensitive consumers, location, consumption, etc.) in order to take the adequate advanced gas quality and hydrogen handling measures whilst avoiding market fragmentation and preserving an integrated gas market.

  It is known that green hydrogen production might fluctuate with variable renewable energy production and the injection in the grid could create variable hydrogen content in the grid, which not all users can adjust to. In order to manage and measure the gas quality and meet sensitive customers' requirements, gas network operators will have to deploy and use enhanced models and advanced gas quality measuring, tracking, forecasting, and data sharing tools. Other gas quality management tools (e.g., deblending) can/will be additionally

[20] ACER: *"Possible regulation of hydrogen networks"* (link)

used. The combination of blending, advanced gas quality & hydrogen handling tools and potentially deblending, can be a solution for sensitive end-users as well as for users consuming only hydrogen. Moreover, information exchange among relevant market players (upstream operators, shippers, producers, TSOs, DSOs, SSOs, consumers, etc.) on gas quality and quantities should be promoted in order to improve forecasts on gas quality variability.

The above-mentioned solutions can be implemented but they will represent an extra cost. NRAs, end-users and infrastructure operators are expected to discuss solutions to address the extra cost for infrastructure operators derived from handling the gas quality requirements from hydrogen sensitive consumers. When doing this, infrastructure operators (TSOs, DSOs, SSOs) should be allowed to recover their efficiently incurred expenditures for investing in such advanced gas quality systems.

- **Guarantees of Origin**

  Hydrogen admixtures in the gas network should be properly recognised within the European energy regulatory framework in order to enable its rollout. A robust system of certificates/guarantees of origin (GOs) would allow the decoupling of the hydrogen physical flow from its climate value, making it possible to trade GOs, and for consumers wishing to do so, to claim a (more) decarbonised gas consumption based on the acquisition of GOs. The consideration of the EU gas grid as a single logistical facility would enable the cross-border trade of GOs. Moreover, GOs will allow for the monetisation of injected hydrogen while reducing the need for public support.

  It is not the purpose of this document to elaborate on what concrete GO system is required. However, GIE expects that any producers injecting hydrogen into the gas grid should be allowed to issue a GO which should include information about its origin and carbon footprint following a LCA and maintain its full value and validity also for hydrogen blended in the gas grid.

6 The Role of Underground Gas Storages in Hydrogen Blending

In Europe, four types of underground formations can provide large-scale cyclical and seasonal storage of hydrogen to secure its supply, allow electrolysers to operate flexibly and assist electricity to cover peak demand: salt caverns, aquifers, depleted fields and rock caverns.

Salt caverns are suitable for storing pure hydrogen. This technology has already been used for many decades at large scale in Great Britain and the United States confirming unequivocally the technical feasibility of this option.

Regarding storage in porous rock (e.g. aquifers and depleted reservoirs), the dissolution and transportation of hydrogen in water, its fingering and confinement in storage are well known and similar to natural gas. Besides, current research to identify potential geochemical or microbiological reactions within the reservoirs is ongoing.

In case of hydrogen blending, all the consequences of the hydrogen admixture especially on the integrity of the storage facility (seals and components installed, compatibility of identified materials, reduction of marketable capacity, etc.) are to be carefully assessed on a case-by-case basis before injection. This is done to ensure that there will be no migration out of the reservoir and alteration of the rock. The ongoing studies are showing a fair potential (see Figure 5).

The analysis of storage assets shows that the injection and storage of hydrogen/natural gas admixtures of more than 2% have significant technical and commercial impacts on surface and subsurface storage facilities for all types of storage assets. Therefore, there is a need to assess and handle adequately those technical and commercial impacts to enable blending in gas storage facilities.

Storage type	Depleted field	Aquifer	Salt cavern	Lined rock cavern
Suitability for hydrogen	Hydrogen-methane blending (up to 10% hydrogen) proven; pure hydrogen storage under study	Under study, but learnings from depleted fields can be utilised	Proven	First hydrogen storage in development (2022)

Figure 5: Suitability of underground storage types for hydrogen[21]

When blending hydrogen, one of the main challenges is to maintain a constant gas quality with a defined range of hydrogen content. Since the main production of renewable hydrogen would take place during summer when there is lower energy demand, hydrogen share percentage within the gas network could be higher during summer than during winter. Underground gas storages prepared for handling mixtures will not only shift hydrogen volumes from summer to winter, but will also balance the network concentration[22]. When precise hydrogen levels need to be achieved, deblending technologies (i.e. membranes) could improve this process even further.

7 Deblending

Hydrogen deblending is the reverse process of hydrogen blending. It allows to extract high purity hydrogen from H_2/natural gas mixtures which can be used:

- for dedicated uses (e. g. hydrogen fuel cells, feedstock)
- providing hydrogen-free natural gas.
- protecting sensitive natural gas end-users against H_2 content.
- for transportation[23] of high purity H_2

For hydrogen deblending, different designs of membrane plants and combinations with other technologies are used (e. g. polymer membrane, carbon membrane, metal membranes, glass/ceramic membranes, membrane-PSA, etc.) to separate hydrogen from gaseous energy carriers.

There are several important factors to be considered when choosing the most suitable separation technology. Additionally, hydrogen separation effectiveness also depends on the hydrogen concentration in methane. While deblending is technically possible, it has still a high relative cost. The availability and affordable cost of deblending technologies for large volume of gas is still to be clarified. This technology is therefore currently under development and additional R&D efforts are needed to make it commercially viable.

[21] Source: *Picturing the value of underground gas storage to the European hydrogen system* (link), GIE *(2021)*

[22] ENTSOG/GIE/Hydrogen Europe: *"How to Transport and Store Hydrogen – Facts and Figures"* (link)

[23] i.e. possibility of moving hydrogen from point A to point B within a mixture and having high purity hydrogen available at point B after deblending; this hydrogen can be used later for dedicated uses or even transported further via dedicated pipelines, trucks, etc.

In some cases, removing H_2 from the gas stream via deblending could be an option to lower the hydrogen concentration to meet the gas quality requirements at IPs or exit points to sensitive customers. How these costs are to be dealt with must be decided beforehand. It is of course not only a technical issue, but also a regulatory and a commercial one since it has to be determined how the extracted hydrogen can be delivered to end-users and at what commercial conditions. Therefore, the responsibilities of each party (TSO, NRA, sensitive end-users etc.) must be clearly defined.

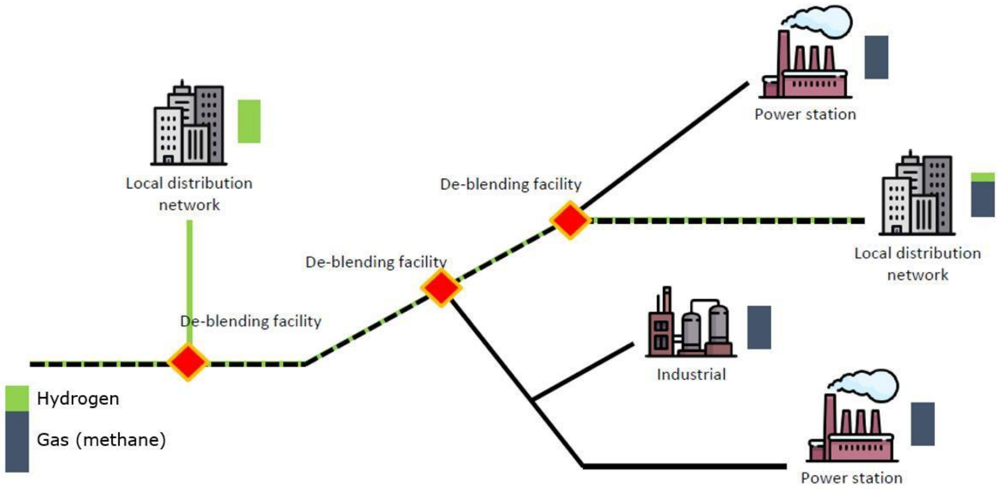

Figure 4: Deblending example for gas quality handling of hydrogen/natural gas mixtures

8 Conclusion and Recommendations

The convenience of blending in a given Member State depends very much on the national circumstances. For some European regions, promoting hydrogen mixtures in the existing natural gas networks is the most effective and affordable stepwise way to quickly trigger the deployment of the hydrogen economy, while using the existing gas infrastructure and ensuring access for hydrogen to an integrated EU gas market. Blending acts therefore as a tool to stimulate hydrogen production and consumption in the short and medium term until hydrogen transport in dedicated pipelines becomes more economically attractive in those regions.

Blending has numerous advantages as well as a number of challenges which can be overcome with the right policy, regulatory and technical decisions. The cost of retrofitting the natural gas transmission network for transporting H_2/Natural Gas mixtures will depend on the maximum desired percentage of hydrogen to be handled, the threshold being 10-20% H_2 share by volume, beyond which the retrofitting costs substantially increase. The underground gas storages are placed to play a relevant role in facilitating hydrogen blending. However, all the consequences of the hydrogen admixture, especially on the integrity of the storage facility, are to be carefully assessed case by case before injecting more than 2% hydrogen.

Deblending is a promising technology which deserves additional R&D efforts and which can significantly help to better manage H_2 concentration in the gas pipelines, at IPs and towards hydrogen sensitive consumers.

Based on the above, GIE recommendations are the following ones:

1. The **new legislative framework** should set up an explicit regulatory framework for hydrogen de-/blending from/into the gas networks. The existing regulatory framework

needs to be changed in order to create the right conditions and set the technical (i.e., via Network Codes) and regulatory rules (i.e., via Directive, Regulation, or other instruments) for gas quality, blending/deblending of natural gas and H_2, and interoperability aspects.

2. Any duly justified **investments of gas infrastructure operators** to enable hydrogen blending should be adequately **remunerated**. Efficiently incurred **gas quality & hydrogen handling costs** should also be fairly recovered for both regulated and non-regulated operators (e.g. SSOs under nTPA regime). NRAs and network operators are expected to discuss solutions to find a regulatory framework which addresses the extra cost of handling gas quality requirements for hydrogen sensitive consumers.
3. Blending as a solution for the application of hydrogen should be **carefully planned** and assessed to ensure that **hydrogen is always used in the most cost-efficient manner**. Expenditures for gas quality handling (i.e. deblending) could be significantly reduced by **planning H_2 injection points** (e.g. location, capacity, and buffer storage size) in line with downstream requirements and possibilities (e.g. right for interruption and/or unacceptance of gas flows).
4. Adequate solutions should be identified to ensure that the existing interoperability of the EU gas infrastructure is maintained, which is crucial for the **integrity of the internal market**. Allow for local and specific solutions to cater for **regional specificities**, without undue impact on the cross-border exchanges of gas.
5. Within the framework of the future applicable EU legislation, **Interoperability should be guaranteed at IPs** to preserve an integrated gas market. A common **EU minimum H_2 admissible threshold** should be considered to facilitate cross-border flows of mixtures. **The Gas Decarbonisation Package could design the process to fix such minimum amongst the concerned TSOs and NRAs,** taking into account interest from relevant stakeholders (e.g. end-users, non-EU TSOs, etc.). **TSOs** should be **allowed to bilaterally agree on higher acceptable H_2 shares** at their respective IPs without an EU cap. This should be in line with their technical and national regulatory requirements and take into account the impact of the agreed H_2 content level on adjacent TSOs who may subsequently receive that gas.
6. Gas network operators are invited to assess the maximum hydrogen blending levels in their gas grids and develop a **Blending Roadmap** to quickly **adapt their networks** in order to deliver their blending ambitions. A clear roadmap, most likely national in nature, would be helpful to understand which milestones in blending levels trigger the need for major investments, and what the whole transition would look like in terms of investments, volumes of hydrogen required, timelines and regulatory changes.
7. Ensure proper **coordination between TSOs, SSOs and DSOs** and enable the timely exchange of information between infrastructure operators and system-users.
8. Favour the introduction by gas network operators of **advanced gas quality handling tools** (based on artificial intelligence, smart metering, enhance forecasts, improved models and simulations, data analytics, digitalisations, asset optimisation, etc.) to ensure that hydrogen concentration is not exceeding the thresholds and limits agreed at national level, with adjacent TSOs and with sensitive consumers and connected storage facilities.
9. **More R&D** is required to better understand the technical impact of different levels of hydrogen blending and hydrogen deblending.
10. Set up a robust and tradable **GO System** that keeps its full value and validity also for blended hydrogen.