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Review Article

A review of technical and regulatory limits for hydrogen blending in natural gas pipelines

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HIGHLIGHTS

- Hydrogen could help to decarbonize challenging to decarbonize sectors.
- Hydrogen blending into the existing gas networks could be advantageous.
- Hydrogen blending impacts on gas network components require a better understanding.

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ABSTRACT

There is rising interest globally in the use of hydrogen for the provision of electricity or heat to industry, transport, and other applications in low-carbon energy systems. While there is attention to build out dedicated hydrogen infrastructure in the long-term, blending hydrogen into the existing natural gas pipeline network is also thought to be a promising strategy for incorporating hydrogen in the near-term. However, hydrogen injection into the existing gas grid poses additional challenges and considerations related to the ability of current gas infrastructure to operate with blended hydrogen levels. This review paper focuses on analyzing the current understanding of how much hydrogen can be integrated into the gas grid from an operational perspective and identifies areas where more research is needed. The review discusses the technical limits in hydrogen blending for both transmission and distribution networks; facilities in both systems are analyzed with respect to critical operational parameters, such as decrease in energy density, increased flow speed and pressure losses. Safety related challenges such as, embrittlement, leakage and combustion are also discussed. The review also summarizes current regulatory limits to hydrogen blending in different countries, including ongoing or proposed pilot hydrogen blending projects.

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Contents

Introduction

Hydrogen is a flexible energy carrier that has the potential to help the integration of renewable energy sources across a variety of energy sectors, including the electricity, heating, transportation, and industrial sectors, among others [1–3]. Hydrogen can be produced from fossil energy sources—through steam methane reforming (SMR) using natural gas and coal gasification—as well as from renewable sources—via electrolysis using clean electricity (e.g. renewables, nuclear power, or electricity from clean grids), thermochemical pathways using high-temperature heat (e.g. from nuclear power), biomass gasification, or photo-electrolysis [4–6]. Fig. 1 provides a schematic representation of hydrogen production pathways as well as related processes and applications.

Once hydrogen is produced, it can be stored and transported in both gas and liquid forms using a diverse set of options, including gaseous hydrogen storage in above ground vessels and salt caverns, cryogenic liquid hydrogen storage in well insulated vessels or tanks, transportation via compressed gas trailers, transportation via liquid tankers, and

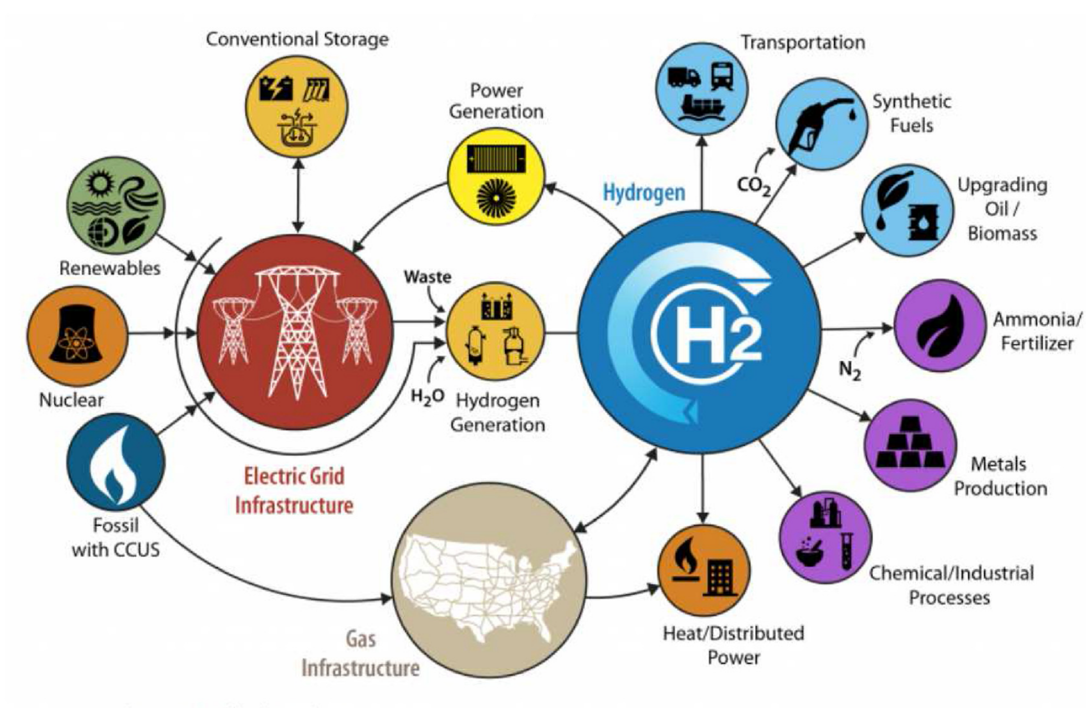

Fig. 1 – DOE H2@Scale Initiative to Enable Large-scale Hydrogen Production and Use in Decarbonization [19].

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transportation via gas pipelines [7–10]. Similarly, hydrogen can be used in a variety of end-use applications, including fuel cell electric vehicles [11–13], seasonal electrical energy storage [14,15], heating [16,17], and industrial processes (metals refining, ammonia production, oil refining, etc.) [18], among others (see Fig. 1).

Hydrogen could be an effective tool for integrating large shares of variable renewable energy sources—namely wind and solar photovoltaic power—in energy systems [20]. For instance, hydrogen could help address the variability and seasonality of these power sources via seasonal energy storage [15] or the decarbonization of difficult to decarbonize energy sectors, such as high temperature heating and industrial processes [16]. However, the cost to develop hydrogen transportation networks could be a challenge for the use of renewable hydrogen in these hard-to-decarbonize sectors. In response to this obstacle, hydrogen blending into existing natural gas transportation networks has emerged as a potentially cost-effective option to transport hydrogen for different end-use applications, using blended gas directly or pure hydrogen after downstream separation [21–23]. Additionally, hydrogen production for blending may support the deployment of renewables, by serving as a flexible demand for electricity.

Direct injection of hydrogen into natural gas transmission or distribution networks is one of several possible applications of Power-to-Gas (P2G), linking the power grid with the gas grid by converting surplus power into a grid-compatible gas. This application has two major implications for end-users. First, since the energy density of gaseous hydrogen is approximately one-third that of natural gas, it reduces the energy content of delivered gas. Therefore, end-users would use larger gas volumes to supply their energy demand. Secondly, hydrogen has environmental benefits if it is produced from low- or zero-emission sources, such as solar, wind, and nuclear energy, as well as fossil fuels that have advanced emission controls and carbon sequestration technologies [14]. However, hydrogen can potentially degrade and embrittle gas pipeline and storage materials [24–26], which may limit the regions where blending is feasible [21,23]. End-use applications, such as existing gas-fired power plants or industrial processes, may not be designed to tolerate hydrogen blending beyond a given limit; for many existing gas-fired power plants, this limit is 5% volume [14]. Accordingly, there is a need to understand the opportunities and challenges for hydrogen blending into natural gas systems.

Several review paper can be found in the literature considering P2G applications [27–29]. In Ref. [27], different technologies used in the conversion of P2G are explained together with potential end-users. An economic assessment is also performed for a case study in Germany to compare the use of hydrogen and methane in transportation. A more detailed economic and technological assessment perspective is provided in Ref. [28], where current electrolysis and methanation technologies are analyzed in terms of P2G supply chain requirements, such as high efficiency, and high flexibility. However, the authors only considered synthetic methane injection into the natural gas grid. A review analyzing the complete conversion of gas distribution pipelines into hydrogen networks can be found in Ref. [29]. On the other hand, Ref. [29] considers partial hydrogen blending into gas grids and discusses the economic and technical challenges of the transition period. State-of-the-art literature typically limits technical analyses to the impact of hydrogen blending on pipelines and does not consider other key facilities of today's natural gas infrastructure.

Reviews of proposed or ongoing P2G projects have also gained attention recently [30–34]. The most recent review [32] examined commercial projects and modeling studies related to P2G for injection of hydrogen into gas grids. The same authors presented an up-to-date assessment of the opportunities and challenges for hydrogen injection into natural gas grids [34]. Additionally, this study applied a value chain optimization model on Great Britain's energy system to analyze partial injection of hydrogen. NaturalHy [35] and Hy4Heat [36] are important studies to understand key conditions under which hydrogen could be added to the pipeline systems where the integrity, safety, and the performance of natural gas appliances are not significantly affected.

This manuscript seeks to provide a current overview of opportunities and challenges for hydrogen blending into natural gas systems within the context of the ongoing energy transition towards 100% carbon-free or renewable energy systems. In contrast to much of the available literature, the technical analysis in this study considers the impacts of hydrogen injection on a range of essential facilities in natural gas transmission and distribution networks. There is currently ongoing research examining the long-term material impacts of hydrogen in existing gas pipelines; as such, this work largely sets aside questions of material integrity and instead primarily focuses on the operational impacts of hydrogen blending addressing key issues such as the tolerance of each asset in the natural gas supply chain, including pipelines, compressor stations, underground storage facilities, and end-use applications. Furthermore, this work summarizes the current regulatory landscape for hydrogen blending, along with ongoing or proposed pilot projects in this space.

The paper is organized as follows. First, we review the operational impacts of hydrogen blending considering key facilities of the system. A review of the literature is complemented by quantitative analyses using a dynamic flow gas network simulation tool. Second, we summarize the regulatory limits for hydrogen blending into gas networks around the world. Next, we present an overview of existing hydrogen blending projects. Finally, we describe the outlook for hydrogen blending, emphasizing the transition from hydrogen blending into natural gas networks to pure hydrogen networks.

Key features of the gas network for hydrogen transportation

Hydrogen has the potential to more tightly couple power and natural gas systems, potentially increasing the integration of these energy systems by means of P2G and Gas-to-Power (G2P) applications [37]. Fig. 2 shows hydrogen some of the role's hydrogen might play in power and gas network interactions.

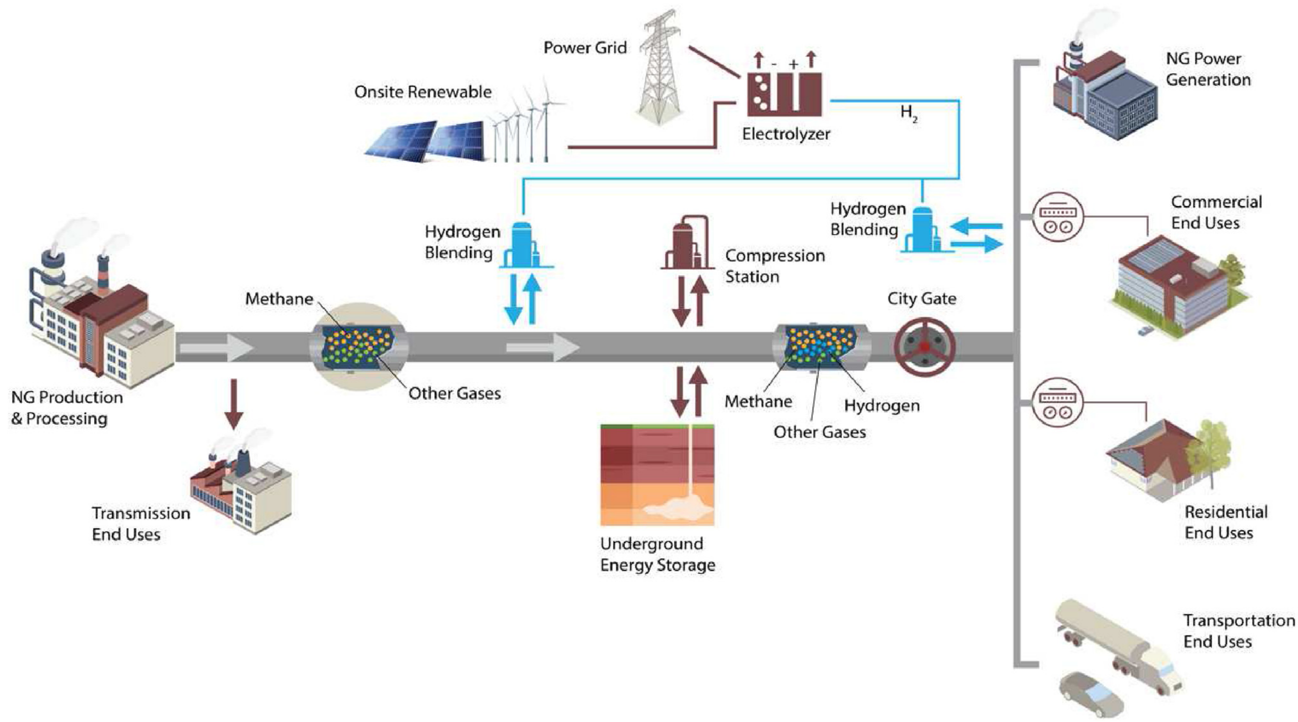

Fig. 2 — Hydrogen's role in power and gas network interactions.

There are numerous advantages to utilizing existing natural gas networks for hydrogen transport. Gas networks are highly reliable and can distribute energy sources with low losses and they can act as a resilient energy storage source through linepack. Hydrogen blending is a near-term approach to increase the share of hydrogen in the energy system utilizing existing infrastructure, until the demand for dedicated hydrogen transport infrastructure is sufficient [38]. Additionally, the use of existing gas networks for hydrogen blending helps to partially decarbonize sectors that are hard to electrify, such as heat generation. To identify specific market sectors that could be early adopters and to properly evaluate the costs and emission benefits of hydrogen blending, additional research is required. The viability of blending will also vary by system, depending on an existing pipeline network's design and integrity.

To date, relatively low levels of hydrogen have been blended into existing gas networks due to legacy pipeline standards based on the natural occurrence of hydrogen in natural gas. The most significant limitations are found in the utilization of materials in industrial applications, gas turbines, and compressed natural gas-mobility, to name a few [39]. Additionally, the current regulatory framework for natural gas could not be directly used for the hydrogen and new standardization will need to be developed considering a variety of issues, including gas quality and safety [23,40,41].

Hydrogen blending tolerances as well as technical and safety standards require a more thorough examination before higher concentrations can be blended. The following section discusses some of the key challenges of hydrogen blending through the gas supply chain and provides an outlook on the transition to 100% hydrogen infrastructure systems.

Hydrogen blending key challenges through the gas supply chain

The natural gas system is comprised of production, transmission, distribution, and end-use systems and the introduction of hydrogen may have an impact on any or all of these systems. Downstream end-use applications in particular can present limitations, and other factors such as injection location, gas network characteristics, natural gas composition, and flow rate must also be considered. When hydrogen is blended with natural gas there are two possible scenarios related with end use impacts. In the first scenario, hydrogen is injected into a natural gas pipeline, transported a predetermined distance, and subsequently removed from the gas stream using separation technologies. After that, hydrogen can be used in a variety of ways, such as in a fuel cell or as a reactant in chemical processes. In the second scenario hydrogen is pumped into a natural gas pipeline network for blending and used as natural gas with a "renewable" component for conventional or dedicated applications [23]. As a combustion fuel, a mixture of methane and hydrogen is employed. The first scenario has some challenges related to separation technologies including high costs and difficulties in maintaining significant blend levels. On the other hand, in the second scenario the main drawback is the impacts of utilization of hydrogen in supply composition on end-use equipment's safety and operations [42]. Table 1 provides a framework for summarizing some of the key challenges of hydrogen injection into gas grids. Regarding the operational perspective, which is the main focus of this review, hydrogen blended gas requires additional considerations in terms of changing gas quality, increases in pressure drop and decreases in pipeline flow capacity.

Table 1 – Key challenges of hydrogen blending.

Key Challenges		
Operational perspective	Safety perspective	Economic perspective
Operation and system impacts	Metal embrittlement of pipelines, compressors, storage, etc.	Infrastructural upgrades
Pressure fluctuations through pipelines	Leakages in pipe joints, seals, etc.	End user switching costs
Gas quality considerations	Low Wobbe Index affecting combustion efficiency	Variable hydrogen production costs
Technical limits of facilities	Differences in combustion properties	Hydrogen separation
Infrastructural flexibility	Fire management	
	Environmental impacts	
	Measurement accuracy	
	Electrical equipment compatibility	

The thermodynamic, transport, and combustion properties of hydrogen are notably different from those of natural gas. Considering that the natural gas transmission pipeline transport system is built for natural gas, there are significant concerns about the compatibility of hydrogen with system components [43]. Hydrogen has around one-third the volumetric energy density of natural gas at ambient temperature, resulting in reduced energy content. As the amount of blended hydrogen increases, the average calorific content of the blended gas decreases, requiring a larger volume of blended gas to provide the same energy demand. With three times the volume necessary to supply the same amount of energy as natural gas, extra network transmission and storage capacity may be required, depending on the hydrogen/natural gas ratio [44]. Pressure drop occurs as the flow rate is increased to retain the same energy density, but the temperature gradient decreases. This could cause issues, particularly if the end users' minimum delivery pressure is not satisfied (e.g., new technology gas fired power plants, cross border export points, industrial users, etc.) Increasing the compression capacity is one option for combating the pressure drop. However, compressor technical limits such as maximum pressure ratio and maximum driver power may limit the capacity growth [45]. Variability in the amount of hydrogen blended into the natural gas stream could also have a negative influence on the performance of equipment built to handle a limited range of gas composition. As a result, the hydrogen/natural gas blend ratio is limited by the capacity and tolerance of the grid-connected equipment. The whole grid's tolerance is constrained by the component with the lowest tolerance. This could be especially limiting for systems with industrial end-use activities that rely on natural gas as a feedstock [46].

The introduction of blended hydrogen in natural gas systems in the future depends on the ability to address these challenges. In the following section the key challenges related to gas system facilities in transmission and distribution system are reviewed in detail. It should be noted that this review paper mainly considers the utilization of hydrogen in supply composition (the second scenario explained above) and the technical limits provided mainly based on the operational considerations rather than safety and economic perspectives (see Table 1).

Gas transmission networks

Transmission networks include different facilities sensitive to hydrogen injection, such as pipelines, compressors, underground gas storage facilities, meters, etc. In addition, gas-fired power plants (GFPPs) and industrial users are also affected by the quality of the gas delivered. As the consumers connected to the distribution network are also fed from transmission pipelines, the gas quality requirements of the downstream distribution level are also affected by the gas quality at the transmission level. Different gas quality requirements within the system can create tracking difficulties and increase the risk of reliability issues. Therefore, hydrogen injection in transmission pipelines requires substantial investments in flow monitoring and metering stations [38], as harmonized and stable gas quality must be ensured.

Transmission pipelines. Gas mixture can significantly affect variables such as pipeline flow rate and pressure levels. As the hydrogen level in the pipelines increases, the thermodynamic properties of the gas and consequently the operating conditions of the pipelines change. The most critical technical changes can be observed in flow capacity, pressure drop, and the linepack profile. As the hydrogen blending level increases, the calorific value of the gas composition decreases. Consequently, there is a significant reduction in the energy flow transmitted to the demand nodes, potentially leading to unserved energy demand without operational adjustments. To meet energy requirements, which depend on the calorific value, the amount of gas to be drawn from supply nodes will increase, and this will cause higher pressure drops along the pipelines, since the pressure drop is proportional to the square of the flow rate. Compensating this increased offtake with increased flow speed brings its own challenges. For instance, systems may have flow rate limits in order to avoid hazards and ensure safe operations. In Refs. [47,48], pressure drop changes under various compositions of hydrogen injection are analyzed and according to the results, pressure drop increases with increasing level of hydrogen providing a constant energy flow.

Additionally, the amount of excess gas stored in the pipelines—referred to as linepack—will also decrease with increased levels of hydrogen injection. The models developed to analyze linepack capacity under hydrogen injection [49,50], show that linepack energy decrease by up to 60% by volume as hydrogen content increases. As less energy can be stored within the pipeline network, reductions in linepack capacity can limit transmission network flexibility which challenges the ability to balance the demand and supply instantaneously at all the times.

Another vulnerability of high-pressure pipelines to hydrogen blending is related to mechanical reliability, which will affect pipeline life. Transmission pipelines generally use low-carbon and high-strength steel. Simultaneous hydrogen exposure and mechanical loads on pipe steel can impose problems related to hydrogen effects. Hydrogen embrittlement is a complicated failure process that is difficult to detect and influenced by many parameters, of which complete understanding is still lacking [51]. In hydrogen pipelines, routine fluctuations in pressure impart stress on the pipeline material that can additionally assist in hydrogen diffusion and enhance hydrogen induced damage. To quantify the level of risk, the influence of reverse and cyclic loads on crack growth needs to be considered. Studies are currently on-going to understand the relationship between the parameters causing hydrogen embrittlement. For instance, the HyBlend project intends to examine the long-term effects of different blends of hydrogen on different pipeline materials [52].

Compressor stations. One of the most important facilities in gas transmission networks are compressors. In gas networks, two types of compressors are mainly used: reciprocating and centrifugal compressors. The flow rate capacity and operating flexibility required for compression are two major criteria that influence the technology selection between the two compressor types [48,49]. Reciprocating compressors are often employed when the volume flow rate is less than 1750 m^3/h (0.47 m^3/s), and centrifugal compressors are commonly used for higher flow rates. Both technologies require higher power to compress blends. While reciprocating compressors for hydrogen service are currently in service, centrifugal designs are less common because their reliability is challenged by the high-power operation and corresponding fast tip speeds required for hydrogen service.

Fig. 3 provides a schematic representation of the pressure drop (Fig. 3a) between two centrifugal compressors, located 150 km apart, and the required shaft power of compressor 1 with different levels of hydrogen composition (Fig. 3b). These calculations were performed using SAInt simulation software, which simulates transient gas network operations [53]. By setting the same inlet pressures (60 bar-g) for both compressors, the outlet pressure of compressor 1 (C1) can be calculated to provide compressor 2 (C2) with the same pressure level. The pressure loss is slightly larger (1.5%) for the 70% hydrogen mixture. The increase is quite small in this example, as the mass flow rate of the system is kept constant just to show the change in compressor pressure ratio with an increasing level of hydrogen. This effect may be more consequential if this pressure loss occurs in all compressor stations in a network and when energy flow is kept constant. Due to increased pressure losses when mixing higher levels of hydrogen, an increased outlet pressure is needed, which increases required shaft power. Existing networks that are now bound by compressor power would require improvements to accommodate the additional power demands associated with blended hydrogen.

Underground gas storages (UGS). Underground gas storage facilities can also be affected by hydrogen admixture as they are not currently designed to store hydrogen. The capacity and efficiency of the storage will change as these parameters are dependent on calorific value, density, and compressibility. From this perspective, additional storage capacity might be needed to reach the same volumetric energy storage [26].

When looking at the types of gas storage in operation around the world, 90% are porous reservoirs (depleted oil/gas extraction areas and aquifers), especially in North America. In Europe, this rate is around 71% [54]. The possibility of chemical/biological reactions in porous reservoirs remains a serious concern. The consumption of hydrogen by microbes poses a risk of hydrogen sulfide (H2S) production, the formation of biofilms near wells, and, in the worst-case scenario, pore clogging. Since actual applications of hydrogen injection in UGS are not common, the amount of gas losses that might occur are presented with estimates based on the literature data [42]. A wide variety of materials are found in UGS systems, including in high-strength steel pipes, casings, connectors, seals, and valves, that would each have to be evaluated to assess the risk of hydrogen induced damage prior to blending.

Although there are not many studies in the literature on hydrogen injection into UGS, available information suggests that the concentration of hydrogen in the stored natural gas in porous UGS is limited to about 5–10% in volumetric terms [26]. Given the above-mentioned risks and uncertainties for porous UGS, this hydrogen storage option is technically more challenging than salt caverns.

On the other hand salt caverns can store up to 100% hydrogen without significant problems [55]. Salt deposits are highly impermeable to gases like natural gas and hydrogen,

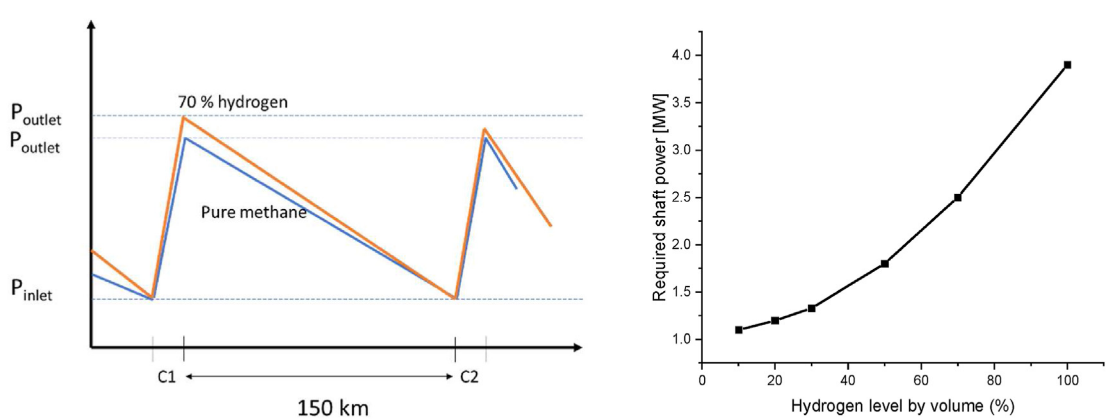

Fig. 3 – Left: Pressure drop between two compressor stations. Right: Required shaft power for C1.

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even at high pressure. The large open cavities that these caverns can represent, with volumes ranging from 10,000 m^3 to over 1,000,000 m^3, are ideal for flexible gas operations with high production and injection rates, and frequent gas cycles [56]. These properties make salt caverns ideal for future hydrogen storage from renewable sources.

Meters and regulation stations. The primary function of regulators in gas networks is to reduce the upstream pressure to lower downstream pressure by adjusting the amount of gas flowing through the regulator. The reduced energy content of a hydrogen blend can also raise a customer's flow demand, which can impact service regulator capacity. Additionally, this might create problems in seals and plugs when the pressure drop through the regulator is greater than 10% of the upstream pressure [57]. Network-specific modifications, such as different material and thicknesses selection and protective coatings, can be applied to control erosion and abrasion.

The performance of metering stations is related to the level accuracy requirements for gas flow. The components of the gas meters and their hydrogen tolerance level will affect the accuracy of the measurements. Fluid property implications associated with blended methane/hydrogen mixtures (low density and viscosity and higher speed of sound) may result in the existing meters being overranged. For instance, most of the meters typically are designed to operate with speeds of sound in the range 300 m/s to 475 m/s. However, the speed of sound for hydrogen is 1304 m/s, almost three times higher than that of methane. Therefore, it is necessary to investigate the long-term stability of the components of the meter with respect to fluctuating gas properties. In addition, permeability and dynamic behavior at high pressures are also important in the determination of hydrogen effects. Leakage can potentially increase due to the smaller particles of hydrogen and wear in internal parts, resulting in reduced measuring accuracy [58]. All these factors can cause the permissible error limits to be exceeded during use and the creation of impermissible blends.

Industrial users and gas turbines. Examining the end-users in gas transmission networks, industrial combustion applications (large burners, furnaces, ovens, cement clinkers, etc.) are highly sensitive to hydrogen injection. Therefore, gas monitoring must be integrated into the system, and the firing process must be carefully examined. If necessary, adjustments are applied, the risk of efficiency losses, heat transfer, and pollutant emissions can be minimized. On the other hand, if the systems are not adjusted, even low concentrations of hydrogen will have negative impacts on industrial users [59]. A similar approach is also needed for large gas turbines producing power.

Gas combustion turbines are expected to tolerate low hydrogen levels (1%–5%) without any technical adjustments, and up to 10% by technical modifications. Turbines that were designed to operate on syngas, however, have commonly already been designed to tolerate very high hydrogen fractions (up to 100%) [54]. For instance, gas turbines by General Electric are capable of operating on a wide range of hydrogen concentrations up to ~100% (by volume) [60]. Siemens plans to demonstrate 100% hydrogen-capable industrial combustion turbines by 2023 in the context of the HYFLEXPOWER project [61]. Mitsubishi Hitachi Power also reports a high-efficiency gas turbine fueled by up to a 30% hydrogen mix [62]. The wide range suggests that there is an opportunity to utilize gas turbines, but that upgrades or modifications may be needed to ensure compatibility with existing infrastructure. Another important point is the rate and range of change of hydrogen content in the gas composition. Industrial-level users may be more sensitive to changes in these parameters. Consequently, these problems and differences must be resolved before the widespread use of high levels of hydrogen injection can be considered.

Table 2 summarizes the available literature on the effects of hydrogen blending in each portion of the transmission network, including limit ranges with some adjustments and modifications. The metrics used in the literature to evaluate the effects of hydrogen injection at each facility are also given separately.

Gas distribution systems

Using blended methane/hydrogen mixtures has different effects on gas distribution networks compared to transmission networks. Due to low pressure levels, sufficient capacity, and various pipe materials, such as thermoplastics, elastomers, and thermosetting polymers, distribution networks are thought to be less susceptible to hydrogen injection. Consequently, increasing amounts of hydrogen in distribution pipelines may be more feasible in the short term than in transmission pipelines. However, end use appliances integrated into the distribution system, such as turbines, burners, micro turbines may have a limited tolerance for hydrogen. More research needs to be performed on the distribution network as well as appliances integrated with the network, particularly where there are many different types of users, especially considering variable demands and gas quality requirements.

Distribution pipelines. Unlike transmission networks, distribution networks are likely to be more tolerant to hydrogen injection as pressure and resulting stresses are generally low. However, distribution pipeline has diverse range of materials which have not been previously studied in detail. Many distribution pipelines use polyethylene (PE); although there have not yet been extensive studies on hydrogen's effects on fatigue and fracture of PE, it is often assumed as less susceptible to hydrogen embrittlement, indicating cautious optimism in the near future [94].

Additionally, the increase in pressure drop in distribution system might be critical in case of high hydrogen blending cases, exceeding 20% by volume [95]. The pressure drop is more of a concern for the transmission system, however the lack of sufficient compressor capacity on the distribution side may result in a failure to meet end-use requirements, particularly in high levels of hydrogen blend.

Another important issue is pipeline leakages, as the accumulation and potential ignition of hydrogen in confined spaces is an essential consideration at the distribution level. However, according to the results provided in Ref. [49], while hydrogen diffusion through polyethylene pipe walls is five times that of natural gas, total hydrogen leakage is still

Table 2 – Key challenges and potential solutions of hydrogen blending in transmission system facilities.

Facilities	Key issues	Potential Solutions	References
Transmission pipelines	- Lower density - Increased flow velocity - Pressure drop - Hydrogen embrittlement	- Increases in the network operating pressures - Adjustment of pressure control systems - Material selection, fabrication processes, material thicknesses - Protective coating - Gas detection devices	[24,37,45,47,48,58,63–80]
Compressors	- Required shaft power - Increased fuel consumption - Increased flow velocity - Maximum pressure ratio limit - Hydrogen embrittlement	- Installation of extra compression horsepower - Protective coating - Adjustment of pressure control systems - Gas detection devices	[37,48,64,68–70,74]
UGS (Porous)	- Reduction in stored energy - Increased reservoir temperature - Hydrogen embrittlement - Microbiological reactions - Geochemical reactions	- Protective coating - Gas detection devices	[26,42,81–83]
UGS (Caverns)	- Geographical limitations	- Development of geographically agnostic reservoirs	[8,55]
Meters	- Decreased metering accuracy	- Adjustment of gas metering and quality control systems - Material selection, fabrication processes, and material thicknesses - Protective coating - Gas detection devices	[58,84]
Regulators, valves	- Hydrogen embrittlement	- Protective coating	[58,84]
Industrial users	- Lower Wobbe Index - Lower gross calorific value - Lower relative density - Increased flame speed - Flammability limits - Ignition probability - Emission limits	- Use of exhaust NOx sensors - Temperature sensors - Pressure sensors	[59,85–90]
Gas turbine	- Lower Wobbe Index - Lower gross calorific value - Lower relative density - Increased flame speed - Flammability limits - Ignition probability - Emission limits - Combustion instabilities	- On-line measurement of fuel composition and compensation through GT control or fuel heating - Combustion system redesign	[54,91–93]

negligible. Therefore, it is evident that more research is needed to understand the hydrogen response of the different material used in distribution pipelines.

End use appliances. The sensitivity of end-users to hydrogen injection is the most critical issue in distribution networks. The service life of domestic appliances that work with natural gas is typically between 15 and 20 years. A diverse base of installed devices comprising new and old technologies can be found in the existing system including gas boilers, combined heat and power appliances, gas heat pumps, water heaters, cooking appliances, catering appliances, space heaters and radiant heaters [96]. In addition to various technology and design levels, there are also differences in combustion systems. For instance, devices respond differently to hydrogen injection based on the fuel-air ratio range, from "fuel-rich" (less than 14.7:1) to "ultra-lean" (greater than 14.7:1) [97].

While fuel-lean appliances (for instance, cooking appliances, hot water heaters and some central heating boilers) are known to be relatively insensitive to flashback, fuel-rich premixed appliances can be considered critical. Fuel-rich appliances (water heaters, space heaters, etc.) are more sensitive to hydrogen injection as hydrogen directly and indirectly (due to the air ratio) increases the flame velocity.

Many studies in the literature have information and laboratory trials on the hydrogen sensitivity of different types of end-users, as shown in Table 3. When looking at the literature related with hydrogen impacts on end appliances, the majority of the studies focused on hydrogen admixture levels less than 30% by volume. The key factors considered can be classified as CO and NOx emissions, flame temperature, flashback, operability, and efficiency. In general, combustion characteristics of end use appliances are found to be very sensitive to increasing hydrogen concentrations. The flame shows significant increases in flame base coupling and flame compaction. According to the results in Ref. [59], it is reported that when using 30% (by volume) hydrogen admixture, power output can be reduced by up to 12% when compared to

Table 3 – Key challenges and potential solutions of hydrogen blending in distribution network facilities.

Facilities	Key issues	Potential Solutions	References
Distribution pipelines	- Leakage - Hydrogen embrittlement - Explosion	- Leak detection by mass balance - Isolation valves	[58,80,100–104]
Boiler	- Lower fuel and air volumetric flows	- Larger safety margins for ignition	[105–108]
Burner	- Increased flashback and reactants ignition	- Burner head, flame detection system and sealing	[99,109–113]
CHP	- Increased pollutant emissions	- Combustor redesign	[107,114–116]
Gas engine	- Lower Heating value	- Flame detection and controls	[117–137]
Micro turbines	- Lower Wobbe index - Water condensate production - Increased flame risk - Combustion instabilities		[98,138–141]
Fuel cell	- Type of technology implemented (PEM or SOFC) - Material temperature design - Material damage	- Strict maximum hydrogen levels - Preventing impurities	[142–147]

operation with natural gas. Furthermore, flashback risk increase is also reported exceeding 20% of admixture ratio. For internal combustion engines, high hydrogen concentrations result in higher combustion temperatures and higher exhaust pressures. High pressures may result in increased emissions and lower thermal efficiency [98]. Gas burners and boilers are also affected by hydrogen injection due to laminar and turbulent flame speed such as 20% hydrogen injection increases the laminar flame by 7% in gas burners [99]. In gas turbines, flame speed increases by 20% with the same amount of hydrogen injection.

Despite the rich literature and laboratory tests on end-user appliances, the available information is insufficient to generalize conclusions due to the high diversity and various technology levels of regional networks with different end-user compositions. The testing procedures used in various studies were found to be inconsistent. This resulted in statements that conflicted with one another, particularly when it came to CO and NOx emissions, as well as flame temperature. Affected combustion control systems have been identified, but the precise nature and extent of the impacts are still unclear. Leakage of hydrogen is also considered a problem, but there are not enough publicly available research results to assess its impact on the domestic technologies.

Overall, it can be concluded that different effects of hydrogen admixture compensate for each other to a certain extent in many common situations found in residential and small commercial appliances. When hydrogen is added to uncontrolled residential combustion systems, the air excess ratio will shift towards higher values, which will largely counteract the increase in laminar combustion velocity and combustion temperatures that will occur as a result of the presence of hydrogen.

When considering the safe operation of natural gas appliances, another important criterion is gas quality parameters, such as calorific value, Wobbe index, and relative density. The Wobbe index is calculated as the high heating value relative to the square root of the specific gas gravity relative to the air [47]. As the Wobbe index of a gas increases, the amount of gas flowing through a given cross-section in a given time will increase and heating value per unit of the gas will also increase.

Admixing hydrogen with natural gas means that new gas quality parameters will be introduced into existing appliances. When hydrogen is injected into a gas network, the Wobbe index of the existing gas decreases. Gas appliances in distribution networks are usually set to a specific Wobbe index (for instance, 53.5 MJ/m^3 for average US gas). If hydrogen is added to the supply gas, heat load and air ratio at the burner will change. Heat load reduces approximately by 7–10% with a 30% addition of hydrogen. In domestic appliances, this performance reduction might be acceptable. However, for industrial users and large boilers, the reduction will be more critical [148]. Continuous fluctuations in the Wobbe index might impact the life cycle of domestic appliances and industrial applications. Fig. 4 shows Wobbe index changes for different gases produced in different locations in the US with various levels of hydrogen injection. The produced natural gas quality can be considerably different and initial methane content of gas can be as low as 65% (Texas example). Important impurities can be observed such as high hydrogen sulfide content in Canada and nitrogen content in Texas. Before transportation of the gas through pipelines, natural gas processing for purification should be applied to obtain a pipeline quality gas which needs to have at least 75% of methane content [149].

As can be seen from Fig. 4, gas mixtures with a small initial Wobbe index are much more likely to fall outside of the normal range. According to Fig. 4, the limit of hydrogen level by volume for the average U.S. gas is 50%. Network risks can be reduced by ensuring a large acceptable Wobbe range from the end-users. However, it is not sufficient to only consider the Wobbe index when defining gas quality. Two gas components with similar Wobbe indexes can have significant structural differences. This should be considered, especially when the hydrogen level in a composition is very high (>80%).

Projects considering hydrogen injection into the gas grid

As detailed in the above sections, additional experience with hydrogen blending into natural gas pipelines will be necessary for operators, regulators, and policy makers to understand the technical and operational implications of different blending levels. Pilot studies and devoted research efforts can provide significant insight into the unanswered questions regarding the consequences of blending, and such activities are essential to understand the capability to blend in current gas

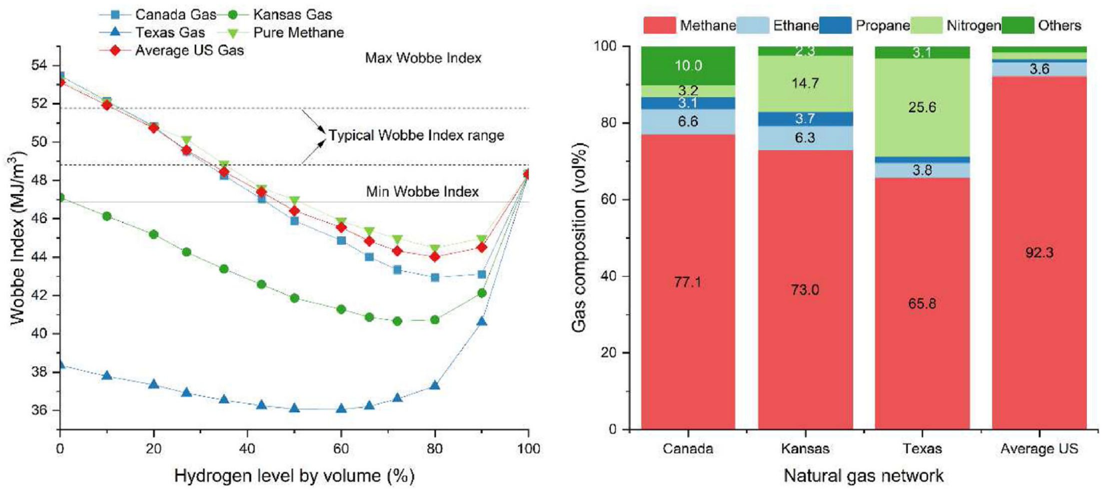

Fig. 4 — | Wobbe index values for different hydrogen blending levels and natural gas production types-gas processing for purification is not considered for this example (assumed gas compositions are shown in the Fig. on the right).

infrastructure. For enabling future commercial and industrial investment in blending pathways, a strong commitment from public administrations to promote innovative projects that demonstrate the feasibility of blending on a small scale is likely crucial. Fig. 5 provides a high-level overview of selected ongoing or announced projects related to hydrogen blending and injection into natural gas networks, with these and additional projects discussed by region in the text that follows. Although most projects that include hydrogen injection into natural gas grids are in the early development stages, some have been successfully operating with hydrogen blend levels for several years. A wave of recently announced projects—particularly in the United States—that are anticipated to begin in the 2021–2022 timeframe suggests that operators and policy makers are increasingly interested in exploring the potential for hydrogen injection and blending in natural gas networks.

Europe

The European Commission's roadmap for making "a climate-neutral Europe by 2050" targets the development of a hydrogen from electrolysis economy as a priority area. In July 2020, the Commission also released "A hydrogen strategy for a climate-neutral Europe" which summarizes the opportunities and challenges that the hydrogen economy's deployment needs to face in Europe [150]. This strategy notes that

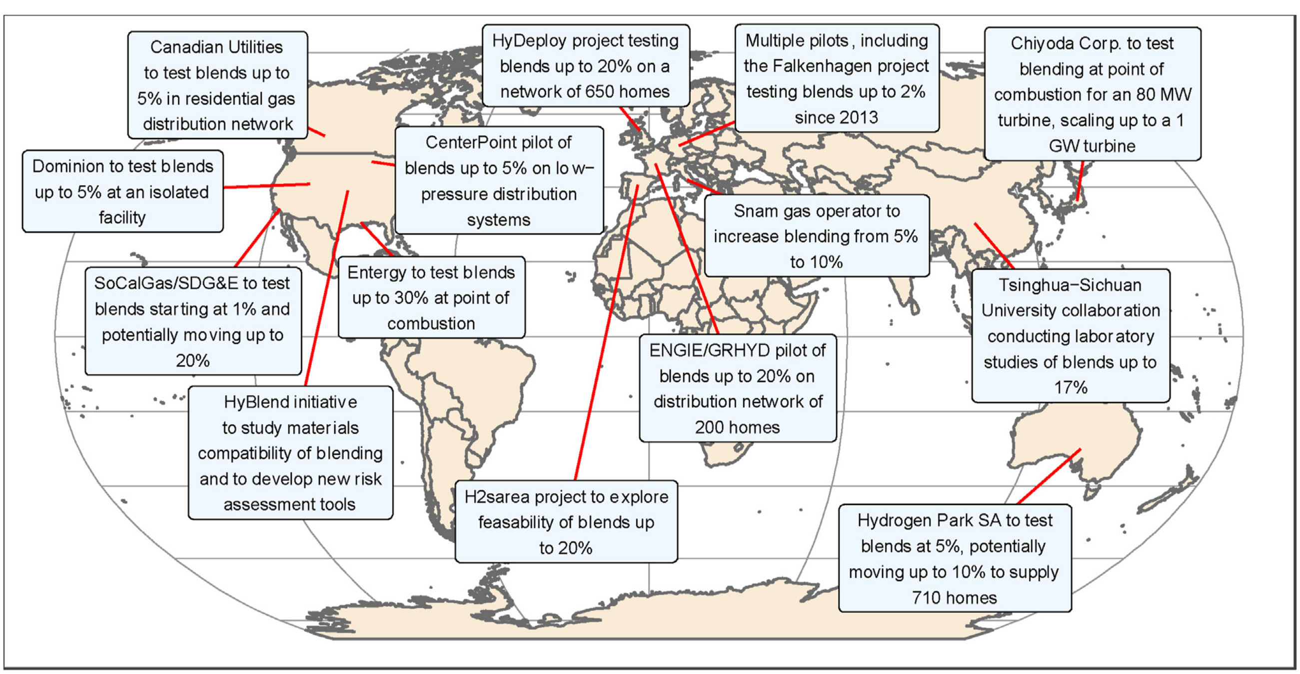

Fig. 5 — Summary of announced or ongoing pilot programs intended to study the impacts of hydrogen blending on natural gas pipeline systems. This Fig. summarizes major pilots and is not intended to be comprehensive. See text for references to pilot announcements and the appendix for a table of project announcement links.

hydrogen blending into natural gas networks is likely to alleviate the immediate need for new infrastructure to transport hydrogen and help enable decentralized, renewable hydrogen production [150]. However, this strategy document also sets out that blending is likely to be useful only at “limit percentages … in a transitional phase” and identifies the need to develop dedicated hydrogen infrastructure in conjunction with using blending to advance the understanding of producing and transporting hydrogen.

In conjunction with these strategic objectives, the European Hydrogen Backbone Initiative [151] has defined a roadmap for upgrading the current natural gas transmission infrastructure to enable hydrogen injection in blended and pure hydrogen pipelines. The effort foresees 23,000 km of hydrogen pipelines, 75% of which will consist of converted natural gas pipelines. The initiative also notes that blending of hydrogen is likely to serve as an effective transition strategy through the 2020s while efforts to repurpose infrastructure projects are underway [151].

Despite these strategic objectives, the European Commission also acknowledges that there is significant uncertainty in the hydrogen blend tolerances of existing infrastructure and that additional research and development efforts as well as pilot projects are required to advance the understanding of hydrogen impacts [41]. Accordingly, many European countries are actively pursuing pilot projects related to hydrogen injection and blending. Germany serves as a leader in projects, with at least eight ongoing or planned pilot projects related to hydrogen injection in natural gas networks [152]. One example is the Falkenhagen project, which since 2013 has been harnessing 2 MW of wind power to produce hydrogen through electrolysis that is then injected into the natural gas network at 2% blend levels [153]. Other hydrogen injection and blending projects are located in Ibbenbüren, Prenzlau, Frankfurt, Mainz (Energiepark), Hassfurt, and Grapzow (RH2-WKA), with injection concentrations reaching up to 10% for some projects [152,154].

France is also advancing projects to test hydrogen production and injection into the natural gas network as part of its national strategy supporting the deployment of hydrogen from electrolysis [155]. In particular, the GRHYD project being conducted by ENGIE and other industry partners aims to demonstrate the feasibility of injecting hydrogen into the natural gas network by testing blend levels up to 20% for distribution to 200 homes [156].

Spain, like its neighbors, has a national policy for advancing hydrogen deployment and is advancing pilot projects to assess the viability of blending hydrogen into the current natural gas network [157]. In 2020, a consortium of companies led by gas distributor Nortegas announced the H2sarea project, which in Phase I intends to test blend levels up to 20% at two technology centers [158]. This project, intended to pave the way for Nortegas to blend hydrogen across its 8000 km of pipeline infrastructure, also includes research in advanced materials, injection and compression systems, sensors, and other equipment needed to manage hydrogen blends [158]. The European Commission is also funding Green Hysland, a project intended to advanced hydrogen deployment on the Spanish island of Mallorca. A core piece of the project is the installation of an electrolyzer for hydrogen production; although the primary objective is to produce hydrogen for direct use, excess hydrogen is planned for injection into the natural gas grid at the distribution level [159].

In Italy, the natural gas transmission network operator Snam began testing hydrogen injections into its network in 2019. The pilot started at 5% hydrogen blend levels and increased blend levels to 10% a few months later, with the blended gas being supplied to two industrial customers [160]. Outside of the European Union, the HyDeploy project will be the first project in the U.K. to test hydrogen blending in existing gas infrastructure. The project will begin with injecting hydrogen into part of a private natural gas network at Keele University campus in Staffordshire [161]. At a later stage, the demonstration will be extended to a public network that serves 650 homes, with tests of blend levels up to 20%. Currently, the project is formalizing the administrative procedure required to achieve regulatory clearance for blending.

The United States

Responding to the California Public Utilities Commission's 2019 request for hydrogen injection standards, two gas utilities in the state—Southern California Gas Company and San Diego Gas and Electric—have developed a collaborative Hydrogen Blending Demonstration Program. In this pilot, hydrogen blend levels up to 20% were successfully tested on an isolated section of primarily polyethylene plastic distribution system in SoCalGas' service territory [162].

Similar pilots to the one being explored in California have been proposed by CenterPoint in Minnesota and Dominion Energy, with blend levels for those projects anticipated to go up to 5% [163,164]. A separate pilot proposed by Entergy would utilize dedicated hydrogen pipelines but would test blend levels up to 30% at the point of combustion at a new combined-cycle facility being developed in conjunction with Mitsubishi [165,166].

In late 2020, the U.S. Department of Energy (DOE) released a strategic plan for hydrogen investments, including research priorities for transporting and consuming hydrogen and natural gas blends [167]. Accompanying that framework, the DOE also announced a new research and development effort dedicated to studying the ability to blend hydrogen into natural gas pipelines. Known as HyBlend, the initiative includes a project committing $11 million in government funding and up to $5 million in funding from ~30 industry partners to understand the cost, emissions impacts, and technical limitations of hydrogen blending given compatibility of pipeline materials with hydrogen [168]. More recently, the U.S. DOE has also announced the Hydrogen Shot, the first Energy Earthshot, with goal of reducing the cost of clean hydrogen to $1 per kg in the next decade [169].

Other regions

Significant interest exists in extending the hydrogen economy in East Asia; however, the majority of strategic planning and research appears to focus on pure hydrogen streams rather than hydrogen mixing. Nevertheless, some blending projects are being pursued, such as a pilot project in Japan exploring the ability to blend hydrogen and natural gas at the point of combustion for an 80 MW gas turbine [170]. In China, the Tsinghua-Sichuan Energy Internet Research Institute is leading laboratory tests exploring the impacts of hydrogen blends up to 17% on natural gas infrastructure [171].

In Australia, the country's national hydrogen strategy document includes several priority areas related to hydrogen blending, but also highlights several barriers to adoption. Specifically, the strategy document notes that while "many existing residential gas appliances are tested to operate under limited conditions with hydrogen at levels of 13%", this level is "not meant to represent a safe upper limit for general appliance operation" [172]. Accordingly, the document calls for an additional pilot test to evaluate not only the technical feasibility of hydrogen blending, but also how it impacts consumers. To that end, Australia is currently investing in the Hydrogen Park SA project, located in South Australia, which includes a 1.25 MW electrolyzer that will produce 480 kg of hydrogen per day. The project expects to inject hydrogen into the natural gas grid serving 710 homes starting at 5% blend levels and potentially moving up to 10% over time [173]. The first supply of hydrogen blended natural gas is started in the first quarter of 2021.

Canada is also advancing hydrogen blending projects, with planned demonstrations set to occur in both Alberta and Ontario. The Alberta project, which received $2.8 million in funding from Emission Reductions Alberta's Natural Gas Challenge, aims to demonstrate blends up to 5% in a section of Fort Saskatchewan's residential natural gas distribution network [174]. The project, led by Canadian Utilities, started operation in the first quarter of 2021. The Ontario pilot is led by Enbridge Gas and aims to provide blended gas distribution service to approximately 3600 residential customers has started in the fall of 2021 [175].

100% hydrogen systems

The idea of a hydrogen economy is not new. A hydrogen-based energy system was conceived in the wake of the oil crises of the 1970s. Hydrogen is also used in chemical reactions such as hydrogenation of crude oil and ammonia synthesis. The late 1990s fuel cell technology discoveries are the fundamental cause for the renewed interest in hydrogen [16]. Fuel cells can benefit from their superior conversion efficiency over internal combustion engines. Additionally, in a low-carbon future, hydrogen could play a crucial role: balancing electricity as a carbon-free energy carrier that is simple to store and transport; allowing for a more secure energy system with less reliance on fossil fuels.

In line with these facts, the demand for hydrogen has increased significantly during the past few decades. According to the International Energy Agency (IEA), the demand for hydrogen, both pure and mixed with other gases, increased from 30 Mt in 1975 to 90 Mt in 2020 [194]. In 2020, more than 70 Mt used as pure hydrogen and the remaining 20 Mt mixed with carbon-containing gases in methanol and steel production. This demand was almost entirely for refining and industrial purposes. Currently, hydrogen is produced primarily from fossil fuels, resulting in over 900 Mt of CO_2 emissions per year. Total hydrogen demand from industry is predicted to grow 44% by 2030 in the Net Zero Emissions by 2050 scenario, with clean hydrogen from renewables becoming increasingly essential (amounting to 21 Mt in 2030 for industry and 5 Mt for refining) [195].

Hydrogen as a clean energy carrier (if produced from "clean" sources) is gaining increasing attention as a policy priority. Creating a broad market for hydrogen as an energy vector can help reduce emissions and provide energy security. Unlike most alternative fuels, except electricity, hydrogen is a secondary energy carrier that can be created from any (locally available) primary energy source, allowing for long-term renewable energy production [61,176]. Hydrogen might also be utilized to store electricity generated by intermittent renewable sources like wind. Assuming large-scale carbon capture storage (CCS) is achieved, clean fossil-fuel power generation might be achieved by producing hydrogen.

However, using hydrogen exclusively for climate policy reasons is difficult. Hydrogen, like electricity, is a secondary energy carrier, not a primary energy source. Like electricity, any benefit from using hydrogen as a fuel depends on how it is produced. It increases supply security but increases CO_2 emissions if produced from coal (unless the CO_2 is captured and stored, a critical prerequisite for this pathway). Non-fossil (nuclear or renewable) fuel production increases supply security and reduces CO_2 emissions, but only in proportion to the non-fossil fuel source utilized.

The challenge with clean hydrogen is the economic obstacle that comes with the higher costs. The cheapest way to produce hydrogen is from methane (~$1-$2/kg) and the price is strongly influenced by the natural gas prices [38]. Hydrogen production via electrolysis is currently approximately $5-$7/kg, and is influenced by various technical and economic factors such as, capital costs, conversion efficiency and electricity costs [177,178]. In 2019, there were at least 142 active electrolysis plants in the world, with a total capacity more than 200 MW which are mainly from pilot projects. The countries with the largest installed capacity are Germany (30.7 MW) and Denmark (2.53 MW) [179]. A reduction in the costs is expected with an increasing number of electrolysis plants but it is still difficult to make a precise estimate as it depends on cost of electrolyzer, their efficiency, the cost of electricity, and the plant capacity factor. However, replacing current hydrogen production capacity with cleaner technologies would not be as difficult as adopting hydrogen for new applications from a technical standpoint.

After hydrogen is produced, hydrogen distribution planning is required to supply demand. If the distance between production and end-users is short, the most advantageous option is to transport hydrogen through pipelines. For this purpose, a dedicated hydrogen network can be developed by converting existing natural gas pipelines or by constructing new infrastructure. When the transportation distance increases, marine and port infrastructure and terminals may be more convenient in terms of cost and flexibility [180]. Just as with natural gas, the financial sustainability of pipelines can be achieved through continuous supply and high-volume transportation. However, transportation via pipelines results in the need for long-term planning and reduced flexibility. On the other hand, ship transportation of hydrogen provides more flexibility, for instance, to supply demand in different countries at potentially higher prices.

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For a technically and economically effective hydrogen system, one of the most crucial concerns is hydrogen storage. A hydrogen economy will be difficult to achieve without effective storage alternatives. Gas storage could be more critical for renewable-driven electrolytic hydrogen production given the variability and uncertainty associated with wind and solar photovoltaic power generation [181]. Salt caverns are considered more suitable than underground storage in porous structures (depleted gas fields, aquifers) due to their large scale pure hydrogen storage capability, and their salt structures limiting the hydrogen contamination [180,182]. In terms of storage volume and modularity, the salt cavern storage system is highly versatile in terms of practicality, as many caverns can be leached on a single site to adapt overall storage capacity to changes in demand. However, because to the low cavern volume (in comparison to an aquifer) and the limited availability of salt deposits appropriate for salt leached cavern constructions, salt structures are only of limited value. In the United States, the United Kingdom, and Germany, salt caverns are already utilized to store hydrogen. Most major salt caverns are found in salt domes near the US Gulf Coast. Salt caves are also found in the Northeast, Midwest, and West, although their applications are limited by geology. In Europe, existing UGSs have an estimated working gas capacity of 50 TWh for salt caverns, and 215 TWh for porous structures, for hydrogen after repurposing. A recent study provided the distribution of potential salt cavern sites across Europe, where Germany has the highest potential with onshore salt caverns located in the northern part of the country [55].

To summarize, all difficulties concerning the usage of hydrogen energy must be addressed if the world's journey towards a hydrogen era is to move smoothly and quickly. Many countries will profit from the introduction of hydrogen energy technologies, particularly because these technologies will aid in the stabilization of many countries' current fossil fuel supply concerns. However, in order to get the benefits, policies promoting the adoption of hydrogen technologies must be established and politically supported.

Regulatory limits to hydrogen injection into gas networks

In the majority of the world, pipeline gas transmission is strictly regulated by one or more regulatory bodies. Injecting and blending hydrogen into natural gas streams would therefore likely necessitate that gas transmission and distribution network operators gain regulatory authorization for the desired amount of blending. Furthermore, regulatory clarity may be needed to ensure that entities interested in developing hydrogen injection and blending projects will be able to operate those projects as intended. Although regulatory bodies are likely to draw on a technical understanding of blending impacts when formulating rules, standards, or requirements, regulations may also reflect additional considerations beyond technical feasibility that could limit hydrogen injection opportunities.

There are now a variety of regulatory procedures regarding hydrogen blending. In general, most countries do not have a specific regulatory approach to hydrogen, and in many cases, hydrogen is simply considered among other hazardous gases. Heterogeneity in regulatory structures and the lack of centralized databases poses challenges to understanding the regulatory context across different countries. Table 4 summarizes the available information on existing requirements regarding the maximum permissible fraction of hydrogen that can be blended into natural gas streams (as a % of total gas volume). Importantly, the absence of a legally stated blend limit does not in most cases imply blending can occur at any level; operators in countries without regulated limits must still adhere to accepted safety norms, with limitations on hydrogen typically considerably less than 10% by volume [183].

In some cases, countries may have no official blend limit but may still impose restrictions. An example is Denmark, which has no set limit *a priori* but requires that the Danish Safety Technology Authority approve the gas composition used by operators [184]. Countries may also have de facto blend limits due to historical operations or accepted norms, such as is in Belgium [184]. In other instances, approved blend limits are conditional on specific characteristics of the network. Germany permits high levels of blending (up to 10%) but requires that networks with compressed natural gas filling stations be kept to lower levels (less than 2%).

Countries that have indicated explicit limits on hydrogen blending with natural gas can be grouped into two categories: those restricting hydrogen to minimal fractions (<0.5% hydrogen by volume) and those that permit larger quantities. As the content of hydrogen impurities in natural gas can be up to 0.5% by volume, requirements at these levels reflect the regulators' desire to ensure natural gas of sufficient quality is transported while acknowledging that some hydrogen may be naturally occurring [183].

Several factors will be necessary for regulators to develop new blending standards or for regulatory clarity on blending limits to emerge. One key component for regulators to set or adjust hydrogen blend limits is information on the technical performance and safety. In a recent survey of European regulations on hydrogen injections, regulators and operators noted concerns ranging from safety issues related to transmission equipment, safety and tolerance ranges for end-use equipment, and sensitivity of industrial customers to changes in gas composition [185]. As part of its emerging national hydrogen strategy, Australia has targeted hydrogen blends as high as 10% for its existing network, but has also stated that regulators will not permit blending until further evidence demonstrates that embrittlement and other issues can be addressed [14]. Similarly, the California Public Utilities Commission solicited input from major gas operators for the development of a hydrogen blend standard; operators responded that they lacked the operational experience to make such a recommendation, and proposed proceeding with pilot test projects with blends as high as 20% [162]. Additional studies and pilot tests are thus likely to be critical for regulators to adopt new blend standards or reform existing limits.

In developing new standards, regulators will also have to address potential conflicts with other legal requirements or standards. For example, gas suppliers may have contractual obligations to provide industrial users with gas at specific energy content levels, which may limit blending capability at the transmission level. In Europe, existing standards require

Table 4 – Regulatory limits on hydrogen blending by country, given as % by volume. Note that the absence of information from this table does not imply that blending is unrestricted. Data compiled from various sources, including the European Hydrogen Law Database (HyLaw) [184], a survey of European regulators by the Agency for the Cooperation of Energy Regulators (ACER) [185], academic papers [186,187], and other sources [14,152,162].

Country	Limit	Notes	Source
Germany	10%	Networks with compressed natural gas filling stations or other "sensitive" customers are limited to <2%.	HyLaw [184]
France	6%	France is currently updating its regulatory framework for hydrogen blends.	HyLaw [184]
Spain	5%	5% allowed for non-conventional gases, but this limit does not represent a hydrogen injection blending limit at the transmission level.	HyLaw [184]
Austria	4%		HyLaw [184]
Belgium	2%	No official limit, but 2% treated as a practical limit by operators; hydrogen injection is currently not allowed but being evaluated by the regulator.	HyLaw [184], ACER [48]
Lithuania	2%	Blending is only permitted if pipeline pressure >16 bar.	IEA [14]
Switzerland	2%		IEA [14]
Canada	2%	De facto limit above which additional restrictions might apply; Alberta gas operator has energy content restrictions that implicitly limit blend levels to 5%	Staffel et al. [186], NRC [152]
Slovakia	2%	No explicit limit; hydrogen can be present in imported gas but not directly injected.	ACER [185]
Czech Republic	2%	The technical standard allows up to 2%, but no requirement for the measurement of hydrogen.	
Finland	1%		HyLaw [184]
Italy	1%	Limit only applies to the hydrogen content of bio-methane; direct hydrogen injection is not explicitly regulated.	ACER [185]
Czech Republic	0.5%		Staffel et al. [186]
Netherlands	0.5%	No official limit at the distribution level, but delivered gas must be <0.5% when received by the customer. Gas transmission entry and exit points must be <0.02%. Pure hydrogen injection is not allowed.	HyLaw [184]
Latvia	0.1%		HyLaw [184]
Ireland	0.1%		ACER [185]
United Kingdom	0.1%		HyLaw [184]
Sweden	0.1%	Blends must be classified as natural gas in the transmission system; allowing levels up to 2% hydrogen has been discussed.	HyLaw [184]
New Zealand	0.1%		Staffel et al. [186]
Japan	0.1%		IEA [14]
California (U.S.)	0.1%	No official limit, but blends above 0.1% trigger additional compliance and monitoring requirements.	IEA [14], CPUC [162]

that hydrogen content must be less than 1% for gas turbine control systems and seals [14]. Additional studies are needed to determine what standards would be impacted and how these might be revised to accommodate higher hydrogen blends, along with policies to support retrofitting or adoption of technology that could be compliant with higher levels of hydrogen content. Furthermore, specific studies will be needed to assess the types of users, their gas-based appliances, and the age and vintage of those appliances to determine whether a system can support higher blend levels.

It is not always clear with which entities the regulatory authority for setting blend limits may reside. In the U.S., pipeline operations are managed or impacted by a range of regulatory authorities, including the Federal Energy Regulatory Commission (FERC), the Pipeline and Hazardous Materials Safety Administration (PHMSA), the Environmental Protection Agency (EPA), the Department of Energy (DOE), and state-level regulators. Currently, regulations and responsibility related to hydrogen are scattered across these agencies, with no clear distinction as to which entity should set blend limits [188]. Although FERC is the most active in regulating pipeline siting, operations, and tariff setting, PHMSA is currently the primary entity managing the approximately 7600 miles of U.S. pipelines that currently transport hydrogen blended gas [189,190]. In addition, it is unclear whether FERC would extend its authority as provided by the Natural Gas Act to hydrogen blends, although there is legal precedent for such a decision [190]. Similar challenges might exist for networked systems that extend across jurisdictions; in Europe, there is a need for international coordination across regulatory authorities of different countries where blended hydrogen would be transported across borders [14].

One path forward for clarity in cases with multiple regulatory authorities is developing a national or international hydrogen strategy, which can identify strategic targets for blend levels, establish roles and responsibilities, and coordinate pilot testing or other studies. A range of countries have developed such strategies, including the Netherlands, Norway, Portugal, Japan, South Korea, Australia, and New Zealand, with Canada and the European Union currently developing similar plans [191]. Although such strategies are not a prerequisite for blending, they may provide sufficient political support or clarity to enable pilot projects, policies, or regulatory adjustments that pursue blending.

An additional unresolved issue related to hydrogen blending that may be relevant in some locations is the lack of a framework for keeping track of the amount of hydrogen injected into natural gas streams, as well as the provenance of

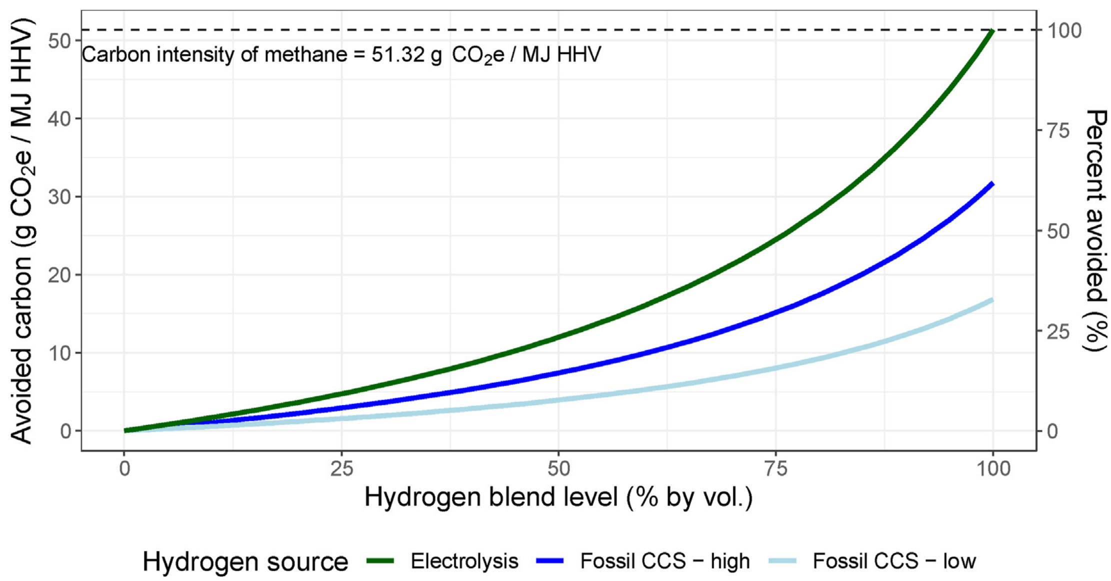

Fig. 6 – Carbon reduction benefit (as a % reduction relative to pure natural gas) of increasing hydrogen blend levels. Benefits are plotting for "hydrogen from electrolysis" hydrogen produced by renewable power (and thus with zero carbon content) and "hydrogen from fossil with CCS" hydrogen produced by natural gas with carbon capture and sequestration; high estimate represents values with 90% capture rate and average upstream emissions from methane production based on historical data in Canada, while the low estimate assumes 80% capture rates and higher upstream emissions factors. Fossil with CCS and upstream emission assumptions are based on estimates in Ref. [84].

that hydrogen. This is particularly important for states looking to encourage hydrogen blending for the purpose of decarbonization, as attributing a carbon intensity to injected hydrogen will be important for tracking emission levels incentivizing low-carbon hydrogen production. California has developed a system by which consumers purchase certificates for renewable methane, while in Europe, the CertifHy project has designed a similar framework for hydrogen [14]. Such schemes can help ensure that clean hydrogen is properly accounted for and rewarded and may serve as incentives that encourage blending in countries pursuing carbon emissions reductions.

Outlook for hydrogen blending

The plethora of hydrogen blending pilot and demonstration projects in recent years illustrates substantial interest from both gas operators and national governments in exploring the opportunities for hydrogen blending. For the most part, these initiatives reflect an interest in deploying hydrogen to help reduce carbon emissions from the natural gas sector while taking advantage of existing gas infrastructure.

Although this paper has discussed the evolving understanding of the technical limitations on blend levels from an infrastructure perspective, it is also important to note that hydrogen blending with natural gas does have limitations in its decarbonization potential. This is primarily due to the fact that hydrogen has a much lower energy content relative to natural gas, meaning that larger volumes are needed to provide the same energy services to end-users as displaced natural gas. Fig. 6 illustrates the CO2 savings at different blend levels, depending on whether the hydrogen that is injected is generated from zero-emissions electricity ("hydrogen from electrolysis") or using natural gas with carbon capture and sequestration ("hydrogen from fossil with CCS"), with the high case representing carbon capture rates of 90% and average methane leakage rates and the low case representing carbon capture rates of 80% and high methane leakage rates. The plot illustrates that for low blend levels by volume (e.g., <20%), the carbon reductions are relatively modest when evaluating on a per energy basis (<10%) [38]. Other work has found that depending on upstream emissions assumptions, hydrogen production with fossil CCS may yield no climate benefits at all [192].

Fig. 6 illustrates an important tradeoff for hydrogen blending into natural gas pipelines: although low blend levels are likely easiest to achieve with the least number of upgrades to gas infrastructure or end-user equipment, high blend levels are needed to achieve substantial decarbonization benefits. This tradeoff points to the long-term need for dedicated hydrogen pipeline infrastructure for entities looking to use hydrogen as a means of eliminating emissions from gas heating and combustion.

Another aspect to consider is the extent to which hydrogen blending creates technological lock-in that prolongs the use of fossil fuels. If blending hydrogen with natural gas increases gas combustion by extending the lifetime of fossil fuel assets or incentivizing new investment, then blending may not achieve its expected climate benefits.

Despite these tradeoffs, hydrogen blending may still offer important benefits in the short- and medium-term. Even though CO2 emission reductions at low blend levels may be modest, the long lifetime and impact of CO2 emissions on the climate imply benefits to earlier reductions in CO2 emissions. In addition, blending into existing pipelines gives gas transmission and distribution network operators the opportunity to build operational experience with hydrogen injection and management while reducing the need for initial large infrastructure investments, and can also offer "off-ramp" opportunities for gas operators to mitigate sunk costs from existing infrastructure.

Furthermore, low levels of hydrogen blending are likely to provide valuable opportunities for continued research on the effects of hydrogen in gas networks and thus offer regulators additional data from which to design new standards or limits for hydrogen injection. In this sense, experience with hydrogen blending may form an important basis for wider adoption of mixed and full hydrogen systems in the future, even if blending itself serves as a transition strategy and not a means for achieving long-term, deep decarbonization.

Conclusions

Hydrogen offers many potential benefits as an energy carrier. When generated via electrolysis from variable renewable electricity resources, it can serve as an energy carrier that enables decarbonization of end uses that are difficult to electrify, such as combustion turbines and heating in buildings and industry. It offers potential opportunities for decarbonizing sectors that have traditionally been thought of as challenging to decarbonize, including high temperature heating and industrial processes. Hydrogen injection and blending into the existing pipeline network offers an additional promise of being able to take advantage of existing infrastructure to achieve these goals.

Despite the opportunities, there are technical obstacles to more widespread blending of hydrogen into natural gas networks. Although conventional wisdom has held that mixtures up to 20% hydrogen by volume are unlikely to cause significant effects, in reality, the threshold at which operations are affected is likely to vary based on the network's material composition, topology, and end-users. While material impacts such as embrittlement have been the focus of much research, operational impacts on compressors, regulators, pipeline flow rates, underground storages, and other network components will also be critical to consider. Furthermore, understanding the energy content implications for operations is an essential next step for operators looking to blend hydrogen into their networks.

These challenges call for additional research and—perhaps more importantly—operational experience with hydrogen blending. Some regions, such as Europe, have had long-standing blending demonstration programs, while others like the United States are witnessing a recent growth in such pilots. These programs will provide essential insight and experience not only to operators but also to the engineers, regulators, and policy makers responsible for crafting the next generation of standards and regulations related to hydrogen and gas networks.

Hydrogen blending into existing natural gas networks may be helpful in reducing CO_2 emission from the gas industry in the short term, which is a critical component of addressing climate change. Nevertheless, it is also important to recognize the limitations that blending faces as a decarbonization strategy. There is an inherent tradeoff in that blending at low levels is likely to be easier to implement but less impactful in terms of emissions, and vice versa. To the extent that blending can build operational experience with hydrogen using existing gas infrastructure, then it is likely to serve as a valuable tool for decarbonization. However, if pursuing blending creates infrastructure lock-in that delays the transition away from natural gas or forestalls investment in dedicated hydrogen transportation infrastructure, then it may serve as a hindrance to those goals. As research and operational experience with hydrogen blending continue, system planners and policy makers should continue to evaluate the role that blending might play in integrated gas and electricity networks.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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