Hydrogen use in natural gas pipeline

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Notice

Executive Summary

With the global focus on moving to renewable energy sources, there is an increased interest in the use of green hydrogen. One potential use for hydrogen gas would be to either use it in place of natural gas or to use a blend of hydrogen with natural gas. The most economical way to do this would be to deliver this gas using currently existing natural gas pipelines. With this idea in mind, the report looks at the compatibility of hydrogen and hydrogen-natural gas blends with materials in the natural gas system, namely pipelines and end-use gas appliances for commercial and residential purposes.

This paper looks at how hydrogen can affect metals and polymers, and whether those effects compromise effective and safe operation of gas delivery. It was found that hydrogen embrittlement was primarily an issue for transmission pipelines but that up to a 50% hydrogen-natural gas blend could be used safely by modifying the current Integrity Management Program. Also included is how the risk of hazards, meaning their frequency and intensity, can be affected by the addition of hydrogen. It is this risk assessment that proposes approximately 20% hydrogen can be added to natural gas without significant increases in risk (for the hazards considered by that program, which focused on hazards related to the gas delivery system rather than appliances specifically).

Due to hydrogen's smaller molecular size, making it more permeable than natural gas, it may be more prone to leaking at joints and valves, and may affect polymer stability.

Leakage can particularly be an issue for service lines and appliances since these are present in locations where gas may accumulate (causing a detonation hazard) and in more densely populated areas. Consequently, it is recommended that polymer compatibility and permeability tests, such as is included in UL 746A, the Standard for Polymeric Materials – Short Term Property Evaluations, be used for appliances.

Hydrogen does have different burning characteristics than natural gas, so it must be determined whether appliances are compatible. Some testing has shown that up to a 20% hydrogen-natural gas blend can be used without notable differences in the function of appliances. At higher percentages, appliances may need to be designed to operate using hydrogen. Important to consider is that hydrogen has a faster flame speed than natural gas, so appliances need to make sure light-back is not an issue. Current appliances in compliance with the EU's Gas Appliance Regulation are tested for preventing light-back for percentages of hydrogen up to 23% (G 222 by EN 437). Another major concern is that hydrogen has a great flammability range and smaller detonation cell size than natural gas, so appliances may need to reduce or remove cavities where gas may accumulate and include venting for any enclosures. More reliable ignition sources may also be a necessity. Other concerns that need to be addressed are performance, whether increased temperatures at surfaces accelerate oxidation and degradation of materials, yellow tipping, blow-off, and emissions (which are related to flame temperature). Hydrogen odorants and flame colorants are also considered.

Hydrogen Use in Natural Gas Pipeline

Background and motivation

Currently, the world is looking for an international consensus to achieve carbon neutrality and is facing an energy shortage, especially in Europe. Many countries believe "green" hydrogen produced by renewable energy could play a key role in helping the world achieve a greenhouse gas-neutral economy by 2050. The addition of hydrogen to natural gas is being considered as an efficient means to utilize existing infrastructure to distribute green hydrogen. The European Commission (EC) expects 1.3 million tons of green hydrogen to be blended into the natural gas network by 2030. If injected with relatively low concentrations, from less than 5% to 20% hydrogen by volume, several studies show that the end-use appliances need no or only minor modifications. However, the suitable blend concentration may vary significantly between the gas networks and natural gas compositions from different sources. The hydrogen admixture also affects some gas properties associated with end-use appliances, such as flame speed, density, calorific value, Wobbe index, air excess ratio and methane number. Consequently, the compatibility of a system with a hydrogen blend must be assessed on a case-by-case basis with extensive study, testing and verifications. Some short-term risks to appliances may be light-back, hydrogen gas leakage and emissions. These should be addressed during a hydrogen compatibility assessment.

Hydrogen is an energy carrier — it is not just an energy source but also an energy storage method. When consumed in a fuel cell, hydrogen is a clean fuel that produces only water vapor, electricity and heat. Hydrogen can be produced from diverse domestic resources. Right now, most of the hydrogen is produced from fossil fuels, such as natural gas and oil. In the near future, as new technologies make alternative production methods more efficient, renewable sources such as biomass, geothermal, solar or wind could be used more directly to generate hydrogen. The concept of using hydrogen blended with natural gas is not new; it can be traced back to the use of manufactured gas produced from coal. This produced a mixture of 30%-50% hydrogen and methane, which was piped during the gaslight era to streetlamps in the early and mid-1800s.[1] The rapid growth in installed offshore wind power solar farm capacity and the influence of Russia's war on Ukraine on energy supply is accelerating the manufacture of green hydrogen and hydrogen blending with the existing natural gas network. Before this war, the EU aimed to increase the share of hydrogen in Europe's energy mix from where it is currently — less than 2% — to 13-14% by 2050.[2]

The permissible volume percentage of hydrogen blending with natural gas networks around the world varies with regional regulation and ranges from 0% up to 20%.[3] The injection of hydrogen could change the performance, efficiency and emission of the end-use appliances. For burners, the flame speed and light-back with hydrogen could be different from natural gas. For boilers, the temperature and calorific value with hydrogen could be higher than natural gas. The nitrogen oxides emissions from hydrogen blending with natural gas used in gas boilers could be increased. If the adiabatic flame temperature generated from hydrogen combustion could be lowered, the nitrogen oxides will be reduced.[4] Therefore, hydrogen blending with natural gas will probably be limited to a volume percentage of less than 20% temporarily.[5]

An important concern is the effect of hydrogen on materials. Different parts of the natural gas infrastructure are made up of a variety of metals and polymers. It is known that hydrogen can affect numerous properties of metals in different ways. This report looks at whether the presence of hydrogen gas, either in its pure form or as a natural gas blend, would have a negative effect on the performance of the metals in the natural gas system. Polymers also make up a large proportion of the natural gas pipeline, so it is assessed whether hydrogen would have a negative effect on their performance. Many polymers used in end-use appliances are related to seals in connections and valves. Sealing materials are typically elastomeric and semicrystalline thermoplastic materials. Of particular concern would be leakage since hydrogen is the smallest and lightest molecule, much smaller than a methane molecule. So, hydrogen could change the permeability and stability of polymers. Some polymers certificated for gaskets and seals of natural gas application have been reviewed for compatibility with hydrogen blending with natural gas or pure hydrogen. The concept of hydrogen compatibility assessment for existing appliances, from raw materials to end-use products, is proposed. It complements the existing verification or certification programs for the polymers, components and appliances. They could be tested and evaluated for pure hydrogen and hydrogen blending as part of conformity assessment in the near future.

Composition and pressures in natural gas pipelines

Two high-level pipeline designations that significantly impact the pressures, pipe sizes, and compositions of the pipes used in the natural gas system are transmission and distribution pipelines. These pertain to different stages in natural gas delivery. Transmission pipelines are used for moving gas long distances around a country, whereas distribution pipelines are those used to deliver natural gas to businesses and homes and are themselves composed of mains and service lines. The transmission systems operate at high pressure and utilize compressors every 50 miles to 100 miles (80 km to 160 km) along its length to be able to increase that pressure as the gas travels long distances. The transmission pipelines then feed into a "city gate," which lowers the pressure of the gas, typically adds odorant, and then feeds that gas into the distribution system. [6]

The pipes in the transmission system are considerably large and can have diameters as big as 48 inches (1219 mm). The following data for pipeline composition are for the U.S. as of 2010. Nearly 100% of transmission pipelines are made of steel, with over 96% being wrapped/coated steel that is cathodically protected and around 3% bare steel without cathodic protection. These steel pipes range from 0.25 inches (6.35 mm) to 0.5 inches (12.7 mm) in thickness. These pipelines carry natural gas at pressure levels between 600 psig and 1200 psig (4.13 MPa and 8.27 MPa), and, in some instances, they may carry pressures as high as 2000 psig (13.79 MPa). The stress levels caused by this pressure can surpass 20% of the specified minimum yield strength of the steel pipes. When transmission pipelines fail, it usually occurs as a catastrophic rupture due to the high internal pressure.[7,8] A common steel used in transmission pipeline is X80 steel, which has a yield strength range of 555 MPa-705 MPa (80 ksi-100 ksi) and a tensile strength range of 625 MPa-825 MPa (90 ksi-120 ksi).[9] However, higher strength steels are being used more such as X120, which has a yield strength range of 827 MPa-951 MPa (120 ksi-138 ksi) and a tensile strength of up to 1023 MPa (148 ksi).[10]

Distribution pipelines have notably smaller diameters and operate at much lower pressures than transmission pipelines. For the U.S. (as of 2010), they consist of 1,201,000 miles (about 1,932,822 km) of distribution mains and 64,804,000 service lines. The service lines are the parts of the system that connect to individual customers. The diameter sizes for distribution pipes generally range from 1.5 inches to 8 inches (38.1 mm to 203.2 mm) for mains and 0.5 inches to 2 inches (12.7 mm to 50.8 mm) for service lines. These pipes carry gas at 0.25 psig to 60 psig (1.72 kPa-413 kPa), though sometimes the pressure can be as high as 100 psig (690 kPa). Possibly worth mentioning is that there are a few pipelines that do operate at up to 400 psig (2758 kPa), but these are designated as high pressure distribution pipelines.[7]

Distribution mains are composed primarily of steel (47%) and polyethylene (48%). The steel grades used include A, B, X42, and X46.[7] These are relatively low-strength steels; for instance, X46 steel has a yield strength range of 317 MPa-524 MPa (46 ksi-76 ksi) and a tensile strength range of 434 MPa-758 MPa (63 ksi-110 ksi).[11,12] The remainder of the pipes are made up of cast and wrought iron (3%), Polyvinyl Chloride (PVC) (1.8%), and Acrylonitrile Butadiene Styrene (ABS) (0.2%). Service lines are composed primarily of polyethylene (63%) and steel (33%) with the remainder composed of copper (1.73%), PVC (0.4%), cast and wrought iron (0.17%), ABS (0.02%), ductile iron (0.001%), and the balance unidentified. At the pressures experienced in the distribution pipeline, steel distribution pipes are being operated at less than 10% of their specified minimum yield strength. Due to the lower stresses in the distribution pipeline, failures typically result in a leak rather than a rupture.[7]

Current failure modes of natural gas pipeline

For both transmission and distribution natural gas pipelines, outside forces are the leading cause of safety incidents. Here, outside forces refer to first/second/third party damage (this includes damage due to excavation), earth movement, lightning, and fire. For distribution pipelines in the U.S. between 1990 and 2002, outside forces accounted for 60.4% of the incidents, including 46.6% of the serious incidents. This is particularly true for service lines, where outside forces accounted for 54% or steel service line incidents and 76% of polyethylene service line incidents. Outside forces accounted for somewhat less of a percentage of transmission line incidents, but still accounted for 39.8% of incidents, including 36.9% of serious incidents. The reason outside forces have a stronger impact on distribution pipelines can be attributed to them being more greatly exposed to higher populated areas.[7]

Another cause for incidents is corrosion, but this is much more so the case in transmission pipelines than in distribution pipelines. For that same date range, 1990 to 2002, corrosion accounted for 23.4% of transmission pipeline incidents compared to just 3.7% of distribution pipeline incidents. Other categories for incidents include construction operating error and incidents accidentally caused by the operator.[7]

Distribution pipeline incidents usually result in a leak rather than a rupture due to the lower pressures/stresses in those systems (ruptures are consequently more of a risk in transmission pipelines). This means that the greatest safety concern for distribution pipes is that an undetected leak, particularly if it is allowed to collect in a confined space, may ignite and cause an explosion. Sometimes the leak can be due to a brittle-like crack in certain types of plastic pipe due to relatively high localized stress, such as may be caused by geometric discontinuities, overbending, improper fitting assembly, gauges or dents. Such a crack may be difficult to detect before a significant amount of leaking occurs, permitting the accumulation of gas such that it poses a safety risk.[7]

Effects of hydrogen on metals

A subject that should be addressed when considering utilizing steel in the presence of hydrogen is whether hydrogen embrittlement will be an issue. Hydrogen embrittlement (HE) manifests itself in a number of ways, including failures due to cracking, blistering, hydride formation, and a reduction in the tensile ductility of the metal. These failures occur at tensile stresses (including residual stresses) below the rated strength of the steel.[7] Hydrogen-induced cracking (which is a term sometimes used interchangeably with hydrogen embrittlement) manifests itself as a time-delayed fracture at a point of tension even though the part is loaded well below its tensile strength. This is due to stepwise internal cracking connecting hydrogen blisters within the metal. High-strength steels are particularly susceptible to this type of hydrogen embrittlement resulting in catastrophic brittle failure. Generally, it is accepted that this includes steels with a tensile strength greater than 1,000 MPa (140 ksi) or with a hardness greater than 30 HRC (301 HV).[14] ASME B31.12 is a bit more conservative, setting a maximum hardness limit of 21 HRC (235 HV) for use with hydrogen piping and pipelines, which correlates to an estimated tensile strength of 783 MPa (114 ksi). This means that the lower-strength steels used in the distribution pipeline (which generally have a maximum tensile strength of less than 110 ksi) are not likely to be affected by hydrogen embrittlement. But, on the other hand, the higher strength steels used in the transmission pipeline, particularly those on the higher-strength range that are more recently being used (such as X120 steel, which has a tensile strength greater than 1,000 MPa), may be susceptible. That is not to say that the steel used in the distribution pipeline will not be affected by the exposure to hydrogen. It is likely that the distribution pipeline steels will lose some of their tensile ductility, but their strength will not be affected to the point where they will fail far below their rated strengths.[7]

Another effect exposure to hydrogen has on steels is that it accelerates fatigue crack growth and reduces fatigue endurance limits of all carbon and low alloy steels (this would be applicable to the steel in both the transmission and distribution pipelines). This is due to hydrogen reducing the ductility of steel. This would be a concern if there are expected to be fluctuations in the pressure within the pipelines. Also because of this deleterious effect on steel's ductility, the crack growth rate from existing defects may be accelerated. However, at the low pressures of the distribution system and the stresses being such a low percentage of the strength of the steel pipes utilized, it is not likely that the distribution pipeline will be susceptible to hydrogen-enhanced crack growth.[7] It is worth noting that distribution pipelines have, in fact, already been shown to be successful in carrying hydrogen gas as they were used historically to carry "town gas" (which contained a mixture of 50% hydrogen, 15% carbon monoxide, 30% methane, and small amounts of other gases).[7,16]

The percentage of hydrogen being used in a hydrogen-natural gas blend may also play a part in determining to what degree, if any, the steel will be affected. According to the California Public Utilities Commission, using blends with more than 5% hydrogen increases the risk of the embrittlement and leaking of steel pipelines.[17,18] It has been found that accelerated fatigue crack growth was notable at 5% hydrogen, with increased hydrogen percentages contributing little additional acceleration.[19]

There has been data that indicates that the effect of hydrogen gas on fracture toughness depends on the pressure of the gas, as is illustrated in Figure 1.[20] However, even at low pressures, hydrogen gas does cause a notable decrease in fracture toughness and this decrease in fracture toughness is not much different for a 1% blend of hydrogen (with nitrogen being used as the balance in this example) compared to 100% hydrogen, as is illustrated in Figure 2.[19] That being said, the steel being used in natural gas pipelines have such high fracture toughness that the detrimental effects of hydrogen exposure are not likely to cause an issue at the pressures seen in both the transmission and distribution natural gas pipelines. For instance, in Figure 1, it can be seen that the fracture resistances of X60 and X80 steels are well above the minimum fracture resistance per ASME B31.12 even at the maximum pressure experienced in transmission natural gas pipelines, 2000 psig (13.79 MPa).[19,20]

Oxygen, O_2, has been known to have a mitigative effect on the effects of hydrogen exposure to ferritic steels. This is due to oxygen diffusion to new crack surfaces. For instance, one can see in Figure 3 how the presence of O_2 in hydrogen deters accelerated crack growth rate, bringing it back to the rate seen in air (0.1% is equal to 1000 ppm O_2).[19] Per U.S. regulations, natural gas may contain 0 ppm-2000 ppm O^2, so it may have enough O^2 to mitigate hydrogen.[19,21]

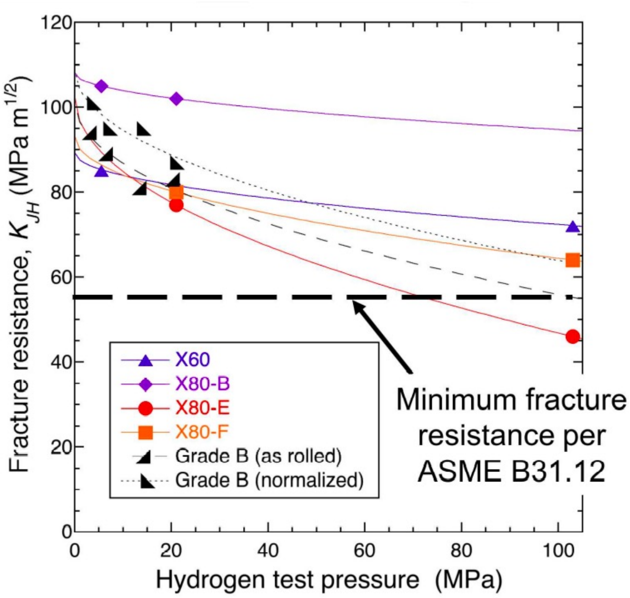

Figure 1: Fracture resistance of X60 and X80 steels with increased hydrogen (100%) test pressure.[20]

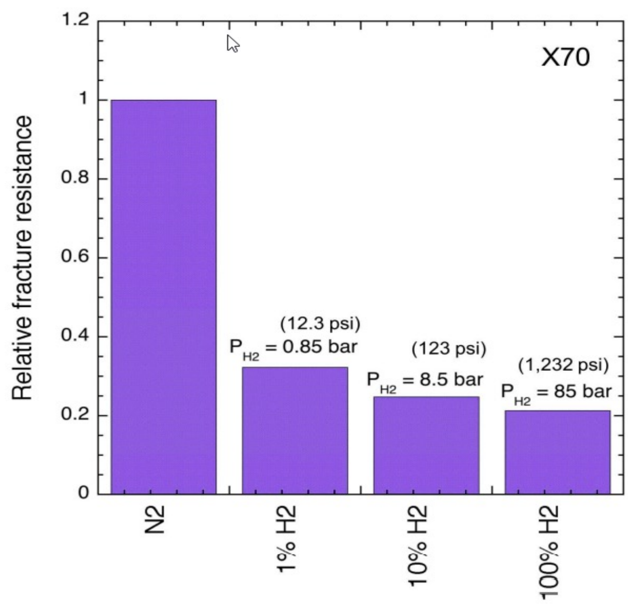

Figure 2: Illustration of how the relative fracture resistance of X70 steel is affected by hydrogen gas even at low pressures. This graph also shows that the effect from 100% hydrogen gas is not much different than 1% hydrogen gas (nitrogen used as the balance gas during testing).[19]

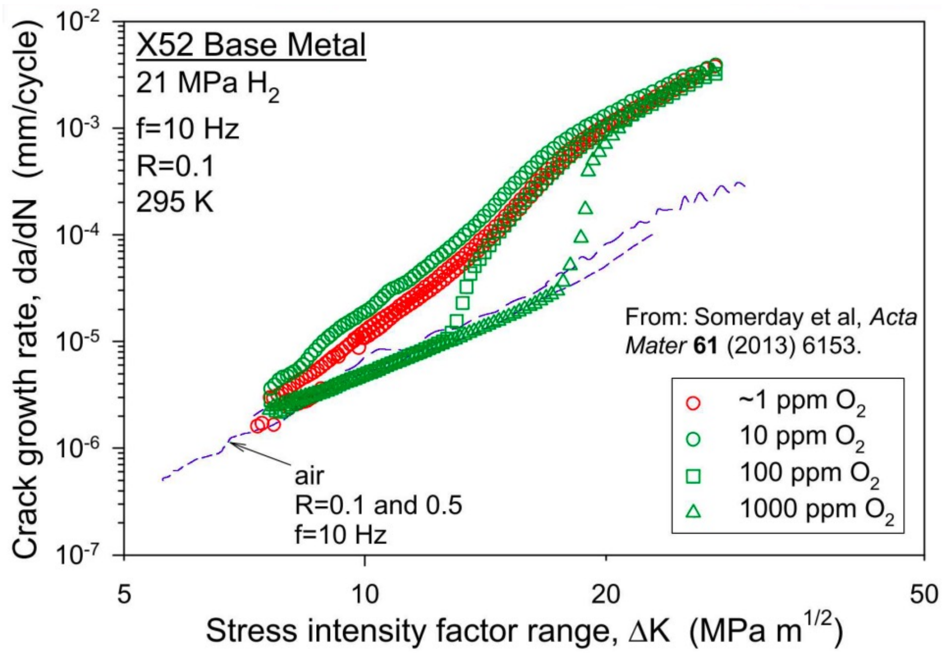

Figure 3: Data from testing with X52 steel illustrating that the presence of 1000 ppm (1%) O_2 in hydrogen gas can reduce the crack growth rate back to that experienced in air. For X52 steel, this is true for a stress intensity factor (ΔK) range up to around 18 MPa m1/2.[14]

It can be valuable to know whether hydrogen embrittlement can be an issue for the other metals that may be present in a natural gas pipeline infrastructure, which can include stainless steel, copper, brass, and aluminum. However, it should be noted that these are primarily used in distribution pipelines and, consequently, are used at lower pressures. Stainless steels are not considered any more prone to hydrogen embrittlement than the other types of steel used in distribution pipelines. Austenitic stainless steels are known to be less susceptible to hydrogen embrittlement than ferritic stainless steels. In fact, 304L and 316L stainless steels are currently used in hydrogen gas service. Copper is generally only considered susceptible to hydrogen embrittlement if it contains oxygen. This is not the case for the copper used in pipelines. Copper and two types of brass (CW617N and CW614N) were tested with a 20% hydrogen blend and did not show significant susceptibility to hydrogen embrittlement. Aluminum pipe is not susceptible to hydrogen embrittlement due to difficulty in hydrogen permeating the aluminum oxide formed at its surface as well as low hydrogen solubility and diffusivity in aluminum.[18]

Effects of Hydrogen on Polymers

According to the California Public Utilities Commission, hydrogen-natural gas blends greater than 20% have a higher potential for permeating plastic pipes, increasing the risk for ignition of leaked gas.[17]

Polymers are not subject to hydrogen embrittlement in the same ways as metals. Hydrogen absorbed by polymers exists as a diatomic molecule, and it does not dissociate as it is known to do in metals. Hydrogen is expected to be inert in the presence of most polymers (not influence polymer properties), but its effects have rarely been explored at high pressures. When exposed to high-pressure hydrogen, some hydrogen diffuses through polymers and occupies the preexisting cavities inside the material. Upon depressurization, the hydrogen trapped inside polymer cavities can cause blistering, swelling or cracking by expanding these cavities. With the development of fuel cell and hydrogen storage technologies, a lot of data on the behavior of polymers and elastomers at high hydrogen pressure has been generated. The failure mechanism reported in those materials, and specifically in elastomers, is related to rapid gas decompression.

The properties of polymers depend not only on their chemical structure, such as chain length, side groups, branching and crosslinking, but also on several important factors. One is the molecular weight of polymer chains, and the other is processing history. Furthermore, fillers, plasticizers, crosslinking agents, flame retardants, etc., are often incorporated to modify properties. The cooling rate of the molten state also changes the degree of crystallinity of polymers. Some standards and chemical compatibility handbooks show that some polymers are stable in a gaseous hydrogen atmosphere. Table 1 illustrates the common polymers' compatibility with gaseous hydrogen.

Table 1: Examples of polymers compatibility with gaseous hydrogen

Chemical Name	Trade Name	Source
Polytetrafluoroethylene (PTFE)	Teflon	ISO 15916 [22]
Polychloroprene (CR)	Neoprene	ISO 15916
Polyester fiber	Dacron	ISO 15916
Polyester film	Mylar	ISO 15916
Nitrile	Buna-N	ISO 15916
Polyamide (PA)	Nylon	ISO 15916
Polychlorotrifluoroethylene (PCTFE)	Kel-F	ISO 15916
Nitrile rubber (NBR)	Buna N	Chemical compatibility (Emerson) [23]
Fluoroelastomers of vinylidene fluoride (FKM)	Viton	Chemical compatibility (Emerson)
Ethylenepropylene (EPDM)		Chemical compatibility (Emerson)
Perfluoroelastomer (FFKM)		Chemical compatibility (Emerson)
Thermoplastic elastomer (TPE)		Chemical compatibility (Graco) [24]
Polypropylene (PP)		Chemical compatibility (Graco)
Polytetrafluoroethylene (PTFE)		Chemical compatibility (Graco)
Ethylene propylene rubber (EPR)		Chemical compatibility (Graco)

Many polymers used in end-use appliances are associated with seals in connections and valves. Sealing materials are typically elastomeric materials such as nitrile rubber (NBR), fluoroelastomers of vinylidene fluoride (FKM), copolymer of ethylene and propylene (EPM), fluorosilicone (FMQ), silicone (MQ), polychloroprene (CR) etc., which have a relatively narrow temperature range for standard operation. Semicrystalline thermoplastics, such as polytetrafluoroethylene (PTFE), polyetheretherketone (PEEK), polyamide (PA), polyimide from pyromellitic dianhydride and 4,4' diamino diphenyl ether, polychlorotrifluoroethylene (PCTFE), etc., are also used in sealing applications and have the advantage that they can be used over a much wider range of temperatures. Table 2 lists the common components of end-use appliances and examples of associated polymeric materials.[25] This table may not include all of the polymers used in end-use appliances.

Table 2: Examples of polymers used in natural gas end-use appliances

Component	Description	Polymers (example)
Flange connections	O-rings, gaskets	nitrile rubber (NBR) fluoroelastomers of vinylidene fluoride (FKM) polytetrafluoroethylene (PTFE)
Valves	Pistons	polyetheretherketone (PEEK)
Valves	O-rings, fittings	nitrile rubber (NBR) fluoroelastomers of vinylidene fluoride (FKM) polytetrafluoroethylene (PTFE)
Valves	Seals and gaskets	nitrile rubber (NBR) fluoroelastomers of vinylidene fluoride (FKM) polytetrafluoroethylene (PTFE) polytetrafluoroethylene (EPM) fluorosilicone (FMQ) Silicone (MQ) polychloroprene (CR) Polyamide (PA) polyetheretherketone (PEEK)
Valves	Valve seats	polyamide (PA) polyimide from pyromellitic dianhydride and 4,4′ diamino diphenyl ether polychlorotrifluoroethylene (PCTFE), polytetrafluoroethylene (PTFE)

How varying the percentage of hydrogen affects metals

As mentioned earlier, hydrogen embrittlement and hydrogen accelerated fatigue crack growth is notable above 5% hydrogen gas and degradation in fracture resistance at 1% hydrogen was little different than at 100% hydrogen. Reports that talk about there being no difference at different concentrations, such as 20% hydrogen, often are referring to the performance of burners rather than pipeline materials. That being said, the effects of hydrogen gas at any percentage do not appear to be an issue for the steels used in natural gas distribution pipelines, particularly at the low pressures (and corresponding low stresses) experienced in those systems.[7]

On the other hand, hydrogen degradation may be relevant in the transmission pipeline due to their higher pressures and the high-strength steels used. One method to mitigate the effects of hydrogen on accelerating fatigue crack growth from existing defects may be to include >1% O_2 in the gas. However, the use of O^2 has not been found to deter hydrogen-induced cracking, which is a potential issue for these high-strength steels, particularly the higher-strength steels being used more recently. To account for this, the NaturalHy Project proposes that hydrogen transportation can still be accomplished by adapting the current Integrity Management Program. What adaptations are necessary would depend on the percentage of hydrogen and pipeline operating conditions, but the adaptations should be manageable for up to 50% hydrogen. This is because the effect of hydrogen on defect criticality is minor up to a 50% hydrogen concentration. Modified inspection tools that can be used to find critical defects include MFL, TRIAX, and EMAT. It is also expected that the intervals between inspections would be shortened for pipelines transporting a hydrogen-natural gas blend. Adequate inspection intervals could be determined using the hydrogen concentration, pressures, geometry of pipeline, and geometry of defects from in-line inspections along with Probability of Failure (POF) calculations.[7, 26]

Safety concerns for hydrogen use (leakage/burning behavior)

The major safety concerns related to adding hydrogen to natural gas pipelines are whether there is an increased potential for rupturing the pipeline, gas ignition, and the increased risk for fire and explosion associated with the leaking of hydrogen or a hydrogen-natural gas blend. The safety risk associated with adding hydrogen to a natural gas pipeline is a combination of the likelihood of these incidents and their potential severity. GTI performed quantitative analysis on this risk based on adding hydrogen to the current natural gas distribution system and compared that to statistical data of fatal incidents from the years 1990 to 2002 and survey results for significant threats from utility operators.[7] However, before looking at the results of that risk analysis, it is important to get a better understanding of these concerns associated with hydrogen that have not yet been addressed, namely its burning behavior and potential for leakage.

The burning behavior of hydrogen has some important differences from natural gas. Perhaps most notable is that hydrogen has a much faster flame speed (2.7 m/s) than natural gas (0.37 m/s). This can lead to light-back in a burner designed for natural gas. Light-back is when the flames burn back behind the burner surface, potentially damaging the burner and surrounding components. Light-back also leads to incomplete combustion of the gas, which poses a detonation hazard. The risk for light-back increases with the reduced speed of gas through the burner, meaning light-back is a particular risk when turning off the burner.[16] As can be seen in Figure 4, the percentage of hydrogen in a hydrogen-natural gas blend has a large effect on the flame speed.[27,28] That being so, the percentage of hydrogen will be a controlling factor determining whether an appliance designed to work with natural gas will function safely with a gas blend.

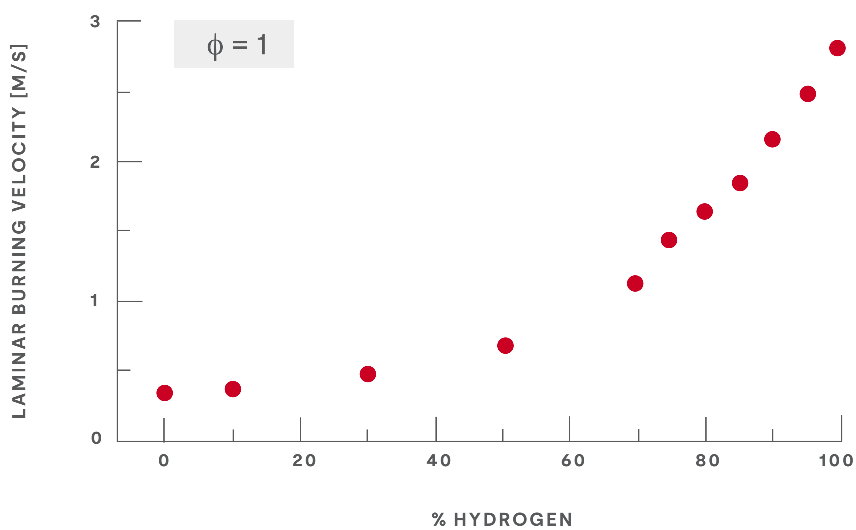

Figure 4: Flame speed of hydrogen-natural gas blend with various percentages of hydrogen at $\phi = 1$. ϕ is the equivalence ratio, so this is assuming a stoichiometric (complete combustion) air-fuel ratio; this infers these burning velocities may be different for lean burning conditions.[30,31]

If, however, higher percentages of hydrogen are to be used, appliances solely designed for natural gas will not likely function safely. To prevent light-back, appliances can be designed with burners that do not have primary aeration. This would make sure there is no combustible gas mixture prior to the point of ignition. Instead, oxygen is only introduced into the flame as it diffuses into it from the surrounding atmosphere. The burner will also need to be designed to ensure the velocity of the gas is greater than the flame speed to maintain combustion. To further prevent light-back, the depth of the burner ports may also need to be increased to achieve better developed flow, reducing possible gas backflow. Other than potential light-back, the increased flame speed also means that a flame containing hydrogen may sit closer to burner surfaces. This, along with the potential for hydrogen to burn hotter than natural gas depending on aeration, means that surfaces may experience higher temperatures and increased oxidation, potentially degrading materials and decreasing an appliance's life expectancy. [16]

Hydrogen differs from natural gas in some other significant ways. Because hydrogen has a much smaller molecular size than natural gas, it is more prone to leakage at joints and valves. Hydrogen also has a larger flammability range (4%-75% hydrogen) compared to natural gas (4%-17% natural gas), as well as having a lower ignition energy for stoichiometric conditions. This means that there can be a greater risk for ignitable gas to accumulate. This is a particular concern for appliances and service lines, which have a greater number of joints and valves, especially in enclosed spaces where the gas can accumulate. For an accumulated amount of gas to be able to cause an explosion, the representative dimension of the gas volume must be greater than its detonation cell width. For natural gas, the detonation cell width is 28 cm (11 in). But in the case of hydrogen gas, this detonation cell width is much smaller at only 1.5 cm (0.6 in). Such a small volume may accumulate in appliance installations and present an explosion hazard; of particular concern are appliances where burners operate in an enclosed space (such as boilers that utilize a sealed casing). 16 The detonation cell size does, however, increase when blending hydrogen with natural gas and detonation is also affected by other factors such as ignition source strength, temperature, pressure, and turbulence of the gas. If the percentage of hydrogen poses an explosion hazard, this can be mitigated by preventing leakage (appropriate joints and valves), reducing the size of internal cavities or eliminating them, providing venting in appliances cases, increasing reliability of ignition sources, decreasing the risk of delayed ignition, and utilizing fast acting combustion sensing methods.[16]

To aid with the detection of any gas leakage, including due to any false ignitions of burners, a gas odorant should be used. The odorants generally used in natural gas, which contain sulfur, would not be good options for use with hydrogen if the hydrogen is also intended for use with fuel cells because they have a negative effect on fuel cell catalysts. 16 This would not be an issue for hydrogen-natural gas blends since hydrogen purification systems would need to be utilized for use with fuel cells. However, if 100% hydrogen is to be distributed, other odorants are being considered that would be compatible with fuel cells.[30,31,32]

The risk assessment performed by GTI showed that the failure frequency of the pipelines would be unchanged from natural gas for blends of up to 50% hydrogen. However, the ignition probability would be higher for hydrogen and hydrogen-natural gas blends due to lower minimum ignition energies and an increase in the upper flammability limit. With that in mind, it is vital to look at the severity of potential incidents. It was found that the concentration of gas buildup was slightly higher with 50% hydrogen but significantly increased with percentages above 50%. Looking at vented explosions, GTI found that blends with 20% hydrogen made little difference in explosion severity compared to natural gas, whereas 50% or higher blends caused notable increases in explosion severity. For gas buildup in confined spaces, explosion severity increased moderately up to 30%, and after reaching 40%, the explosion severity increased significantly. Information on the likelihood of risks and their consequences was used to develop a risk assessment tool (LURAP). It found that the risk to an individual located near a pipeline increased with the addition of hydrogen but that the size of the hazardous region decreased.[7]

The IEA Greenhouse Gas R&D Programme performed tests on hydrogen-natural gas blends up to 25% hydrogen to assess various hazards. A summary of their findings can be seen in Table 3. Their research found that hydrogen-natural gas blends should not increase the risk of explosion when they are used under well-regulated circumstances. However, it found that the probability of fire does increase with the increase in hydrogen.[33]

Table 3: Determination of how adding hydrogen up to 25% to natural gas can have an effect on hazards (taken from report from the IEA Greenhouse Gas Programme).[36]

	HAZARDOUS PHENOMENA					
Cause category	**Rupture**	**Explosion**	**Fire**	**Burns**	**Suffocation**	**Poisoning**
Pressure & chemical properties of gas/heated fluid	X					
Unburned gas in air		- -	+ +		- -	
Use of gas & open fire in a device or heating appliance	X	X	X	+ +		
The appliance itself - outside surfaces and parts				x		
Flue gas system			X	x	- -	- -
Heated media	X	X	X			

X Hazard exists but unchanged by presence of hydrogen

+ + Hazard increased by presence of hydrogen

- - Hazard reduced by presence of hydrogen

(shaded) No hazard of this type from this cause

GTI performed risk analysis for distribution pipelines for hydrogen-natural gas blends and compared those risk factors with those for natural gas; the results of this analysis can be found in Table 4 for distribution mains and Table 5 for service lines. It can be seen that failures due to leaking are most frequently caused by corrosion or excavation damage. While adding hydrogen to natural gas does not change the probability of corrosion or excavation failures, the likelihood of a fire or explosion and its severity may be increased. When comparing the risk factors of natural gas to those of the hydrogen blends, a change in the risk factor of 5 is considered a minor increase, a change in the risk factor of 10 is considered a minor to moderate increase, and a change in the risk factor of 20 is considered a moderate to significant increase. Distribution mains pipelines are considered vented so the change in gas buildup is only slight for hydrogen levels up to 50%. The risk assessment reflects this (Table 4), showing only minor to moderate increases in risk factor up to 20% hydrogen but significant increases in the risk factor above 50% hydrogen. On the other hand, service lines are often in confined spaces, meaning the gas is not able to dissipate as quickly, increasing gas buildup and the probability of a fire or explosion. This is reflected in the risk assessment (Table 5), which shows significant increase in risk factor for all hydrogen addition. The increase in risk factor becomes severe for service lines at hydrogen levels greater than 20%. Based on this outcome, GTI concluded that up to 20% hydrogen can be added to natural gas pipelines without a significant increase in risk.[7]

Table 4: Risk assessment for distribution mains utilizing different hydrogen-natural gas blends compared to natural gas; taken from GTI report.[7]

Failure mode	Probability (%)	Risk factor			
		NG	<20% H_2	20-50% H_2	>50% H_2
Corrosion	36.42	24.54	29.54	29.54	44.54
Material defect	6.98	34.16	39.16	39.16	54.16
Natural force	8.47	25.58	35.58	35.58	45.58
Excavation damage	15.39	50.00	60.00	70.00	70.00
Other outside force	1.86	10.00	15.00	15.00	30.00
Equipment malfunction	6.75	30.00	35.00	35.00	50.00
Operation	2.53	30.00	35.00	35.00	50.00
Other	21.60	10.00	15.00	15.00	30.00
Total	100	214	264	274	374

Table 5: Risk assessment for distribution service lines utilizing different hydrogen-natural gas blends compared to natural gas; taken from GTI report.[7]

Failure mode	Probability (%)	Risk factor			
		NG	<20% H_2	20-50% H_2	>50% H_2
Corrosion	21.64	16.77	26.77	26.77	36.77
Material defect	11.16	35.53	45.53	45.53	55.53
Natural force	3.40	22.95	42.95	42.95	42.95
Excavation damage	24.90	50.00	70.00	90.00	100.00
Other outside force	3.95	10.00	20.00	20.00	30.00
Equipment malfunction	12.71	30.00	40.00	40.00	50.00
Operation	2.57	30.00	40.00	40.00	50.00
Other	19.66	10.00	20.00	20.00	30.00
Total	100	205	305	325	395

Based on this information put together by GTI, 7 NREL has put forward the claim that up to a 15% hydrogen-natural gas blend could be used with only minor modifications to the pipeline, namely modifying existing pipeline monitoring and maintenance practices. Note here that this is lower than the 50% hydrogen blend limit put forward by NaturalHy to account for hydrogen's effect on materials; so, it is fire/explosion related safety concerns that, in actuality, provide an effective limit to the amount of hydrogen that can be safely added to natural gas infrastructure.[7,26]

As mentioned, service lines are composed primarily of polyethylene (63%) and steel (33%). NaturalHy Project investigated the permeation loss of gas from the plastic pipe material of polyethylene (PE). The diameter range from 20 mm to 200 mm of PE pipes was tested at temperatures ranging from 5°C to 25°C and pressures between 14.5 psig and 174 psig with pure methane and blending 10% hydrogen in order to more precisely evaluate the permeation of hydrogen through the plastic pipe in the natural gas distribution network. The results show that there is an incubation time for methane to diffuse through the pipe, while the incubation time for hydrogen is close to zero. Although the permeation coefficient of hydrogen is four to five times greater than that of methane, the absolute values of methane loss calculated for three types of PE piping materials are far lower than the extrapolated data due to the lower partial pressure of hydrogen. From those experiments, it could be achieved that the gas leakages from PE pipes were negligible from an economic point of view.

Polymer materials such as semicrystalline thermoplastic or elastomeric materials have free volume between molecular chains caused by the segmental motion of the molecules. Therefore, the dihydrogen could easily diffuse into a bulk material and permeate from the material. There are multiple methods to determine the permeability properties of a gas, such as the gravimetric method, the manometric method, the constant pressure method, the differential pressure method, the pressure sensor method and the thermal desorption analysis gas chromatography (TDA GC) method. To allow for the conformity assessment of permeability properties, some methods have been standardized, as illustrated in Table 6.

Table 6: Examples of standardized methods for permeability properties.

Measurement method	ASTM	ISO
Differential pressure method		15105-1 [35]
Constant pressure method		15105-2 [36]
Manometric method	D 1434 [37]	2556 [38]
Pressure sensor method		7229 [39]
Gas chromatography method		7229
Gravimetric method	E 96 [40]	2528 [41]

International testing using hydrogen in natural gas pipelines

As of the writing of this paper, the amount of hydrogen permissible in natural gas pipelines varies greatly from country to country. Figure 5 gives just a sample of the variety of hydrogen limits seen in European countries, having a range of limits from 0.1% to 12% by volume.[19] This lack of harmony between regulations seems to indicate gaps in knowledge over how the percentage of hydrogen will interact with pipelines as well as appliances. Reports (such as this present one) have been put together to identify pertinent knowledge, and demonstration type testing is being performed internationally to gather data to support what is safe to use in practice. Some noteworthy reports put together in the U.S. include reports from the Gas Technology Institute (GTI),[7] the National Renewable Energy Laboratory (NREL),[37] the California Public Utilities Commision (CPUP),[18] the Frazer-Nash Consultancy (particularly concerning appliances),[16] and NaturalHy.[26] Some of the demonstration testing projects being performed internationally include:

- France – Using 6%-20% H_2 in Dunkirk in buses and 200 residential homes.
- Italy (Snam Project) – 5% H_2 in gas transmission network.
- U.K. (H21 Leeds CityGate Project) – Converting current natural gas network to work with 100% H_2.
- U.K. (HyDeploy Project) – Testing up to 20% H_2 blend.
- U.S. (SoCal Gas/UC Irvine Project) – Blending H_2 into campus pipeline, H_2 produced using renewable electricity.
- Germany (E.ON Technologies Project) – 10% H_2 blend used by 170 customers.
- Netherlands – Up to 20% H_2 blend being used in Ameland.[19]
- U.S. (HyBlend Project) – Examining long-term effects of hydrogen at different hydrogen-natural gas blends on different pipeline materials to create publicly available models; collaboration with the National Renewable Energy Laboratory (NREL) and five other DOE laboratories. [42,43]

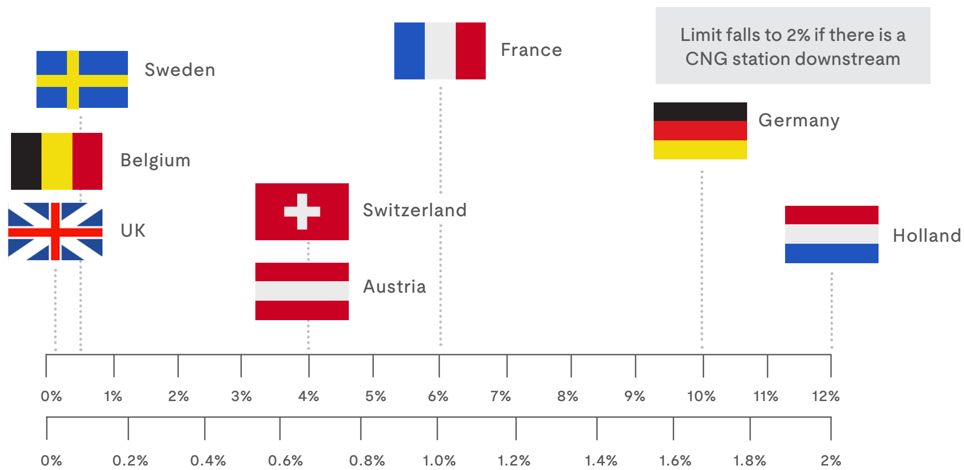

Figure 5: Hydrogen limits for natural gas pipelines in several European countries. [19]
Ref: George Minter, SoCal Gas "New Natural Gas Pathways for California: Decarbonizing the Pipeline" Presentation 2014.
Ref: SoCal Gas "Hydrogen: Market Fundamentals, Trends and Opportunities", California Hydrogen Business Council, December 11, 2018.

One of these projects, HyDeploy, is a program consisting of a series of trials being conducted in the U.K. to build evidence demonstrating that blended hydrogen can be used safely. The first trial took place at Keele university from November 2019 to March 2021 using a 20% hydrogen blend and included 100 homes and 30 university buildings. The success of the first trial led the program to perform a larger second trial, this time performed at Winlaton, from August 2021 to June 2022, including 668 houses, some small businesses, a church, and a school. This second trial, which also used a 20% hydrogen blend, was also found to be successful. HyDeploy, as of December 2022, is continuing to gather data through industrial trials to provide adequate evidence to support U.K. government decision-making concerning the future blending of hydrogen in their natural gas pipelines. So far, this has included the successful use of 20% hydrogen at two industrial sites: Pilkington Glass and Unilever. HyDeploy is also working with Lucideon to develop a ceramics kiln that can use a hydrogen blend gas[44,45] One of the potential issues for appliances when using hydrogen or a hydrogen-natural gas blend is light-back. According to HyDeploy, all new appliances have been tested for light-back since 1996 using a 23% hydrogen blend.[46] This is referring to appliances tested to compliance with Gas Appliance Regulation (G 222 by EN 437).

It is worth noting that in certain parts of the U.S., natural gas with some addition of hydrogen is already being used. For example, Hawaii has been accepting gas blends with up to 15% hydrogen in their pipeline network. [47]

Appliances – will they work with hydrogen or need to be replaced?

Due to certain differences between hydrogen and natural gas, such as flame speed, burn temperature, and leakage, current appliances that burn natural gas would need to be replaced or altered to be able to work with 100% hydrogen. On the other hand, there is evidence and testing being performed to support that current appliances may be able to perform adequately using a hydrogen-natural gas blend. [16]

According to the California Public Utilities Commission, appliances that currently utilize natural gas may need to be modified to avoid leaks and equipment malfunction for hydrogen-natural gas blends above 5%.[17] However, testing elsewhere has shown that higher percentages may be used without customers noticing any notable difference in the function of their appliances, including at a 20% blend in testing in the U.K.[47]

For increased percentages of hydrogen or for use with 100% hydrogen, there will need to be changes to current appliances. Some safety and functionality concerns that need to be addressed include hydrogen's flame speed, potential leakage, flammability, explosion properties, flame temperature, emissions, and flame color. Due to hydrogen's flame speed, burner designs need to be altered to prevent light-back (such as methods described earlier). The flame speed may also cause the flame to sit closer to the burner. This may need to be accounted for since this would cause higher temperatures near the burner surface and, consequently, accelerate the degradation and oxidation of surrounding materials. Due to its smaller particle size, hydrogen is more likely to leak at valves and joints. This combined with hydrogen's larger flammability range, decreased minimum ignition energy, and decreased detonation size makes explosion hazard a great risk, particularly for appliances since they are generally located in populated areas. To account for this, appliance designs would need to minimize or eliminate any enclosed cavities where gas could accumulate, increase venting, increase ignition reliability for burners, and potentially replace joints and valves with options that better prevent hydrogen leakage. Additionally, burners could integrate flame detection devices. Depending on the resultant flame temperature and flame size, this could affect cooking performance of stove hobs. Some potential design solutions include using wedge-cavity (slot) burners, matrix (surface) burners, or catalytic burners. For boilers, heat exchangers may need to take into account hydrogen's different heat transfer characteristics. [16]

Further looking at appliances for use with higher percentages of hydrogen, flame color may need to be considered. Natural gas burns with a pronounced blue flame but hydrogen burns with a pale blue flame that can be difficult to see, particularly in bright surroundings. This poses an issue when the visibility of a flame is used to confirm ignition, such as with a stove hob or a boiler that uses flame checks during maintenance. The aesthetic of the flame color can also be important to the attractiveness of an appliance, such as a gas fireplace. One method being researched is using additives in the gas to change the color. Such additives would need to be food safe in both burned and unburned condition and their impact on flame characteristics would need to be investigated. Manufacturers are also looking at adding appliance design features that utilize various methods of changing the flame color, such as due to the burning of particulate from metal fiber blankets or the vaporization of oils. Beyond visible color, hydrogen flames also emit a considerable amount of UV, so any related safety implications should be considered. [16]

Thought has been put into how manufacturers, along with consumers, can handle the change to appliances designed to operate using elevated or 100% hydrogen. To satisfy customers, manufacturers want to avoid drastic alterations to the size and appearance of current appliances, including utilizing similar-sized burners and other associated components. To move forward, if and when such a change in gas supply were announced, manufacturers could offer a few different options to customers. The first option would be to purchase new appliances designed specifically for use with hydrogen. This option would likely result in appliances with optimal efficiency and safety but would not work in the interim between switching from natural gas to hydrogen. Another option would be to supply customers with conversion kits to adapt current natural gas appliances to run on hydrogen. Whether such a conversion kit could be made for each appliance would require evaluation of the safety/risk involved with users installing such a kit (including looking at the consequences of potential mistakes in installation) and whether switching that appliance to hydrogen could negatively impact its continued performance, reliability, and lifetime. A third option would be to supply customers with new appliances that could be used with natural gas or hydrogen. It is thought, though, that appliances designed that could readily switch between natural gas and hydrogen could be too large and expensive than would be acceptable to customers. More practically, dual-fuel appliances could be designed such that they are hydrogen-ready; this would mean that these new appliances would work for natural gas but can be made to work with hydrogen by replacing certain parts. By designing these appliances with the idea in mind that these components need to be changeable by users, they can be designed to accommodate this safely and reliably. [16]

Hydrogen compatibility testing of appliances

When looking at whether an appliance will safely function using hydrogen or a hydrogen-natural gas blend, there are a number of factors that need to be addressed. For the polymers in the appliances, their physical and chemical properties comply with some standards, such as UL 746A, the Standard for Polymeric Materials - Short Term Property Evaluations, for use in natural gas appliances.[48] However, this is not the same as being approved for use with hydrogen. There is almost zero lag time for hydrogen to penetrate the sealing polymer materials because the permeation rate of hydrogen is four to five times faster than natural gas in the distribution network. Therefore, if the polymer materials will suffer from pure hydrogen or hydrogen blending with natural gas, their stability and permeability with hydrogen should be taken into account.

Some standards of components, such as UL 25, the Standard for Meters for Flammable and Combustible Liquids and LP-Gas, require evaluation for compliance with safety requirements. For gas flow/volume meters, they have diverse measuring principles such as differential pressure, temperature or flow rate. According to this, the compatibility of pure hydrogen or hydrogen blending depends on the measurement method and needs further investigation. For combustion appliances that were designed to operate with standard gaseous fuels such as natural gas and liquefied petroleum gas, hydrogen blending will bring different design mindset challenges. Its faster flame speed, increased flame temperature, reduced volumetric density, wider flammability range, reduced flame luminosity, etc., could influence the performance and safety of the existing appliances when used with pure hydrogen or hydrogen blending. Some short-term risks to appliances may be light-back, hydrogen gas leakage and emissions. These should be addressed during the hydrogen compatibility assessment.

Figure 6 shows the concept of hydrogen compatibility assessment for existing appliances, from raw materials to end-use products; this assessment complements the existing verification or certification programs for the polymers, components and appliances. They could be tested and evaluated for pure hydrogen and hydrogen blending as part of the conformity assessment in the near future.

New pipeline constructions being considered for hydrogen delivery

If the hydrogen-natural gas blend that will be used has a higher percentage of hydrogen than is compatible with current pipeline materials or if the switch will be to 100% H_2, constructing a new pipeline would be necessary. A potential material being given serious consideration is fiber reinforced polymer (FRP) pipelines. This material has the advantage of being 20% cheaper to install than steel because it can be produced in longer sections than steel, consequently reducing welding requirements.[50]

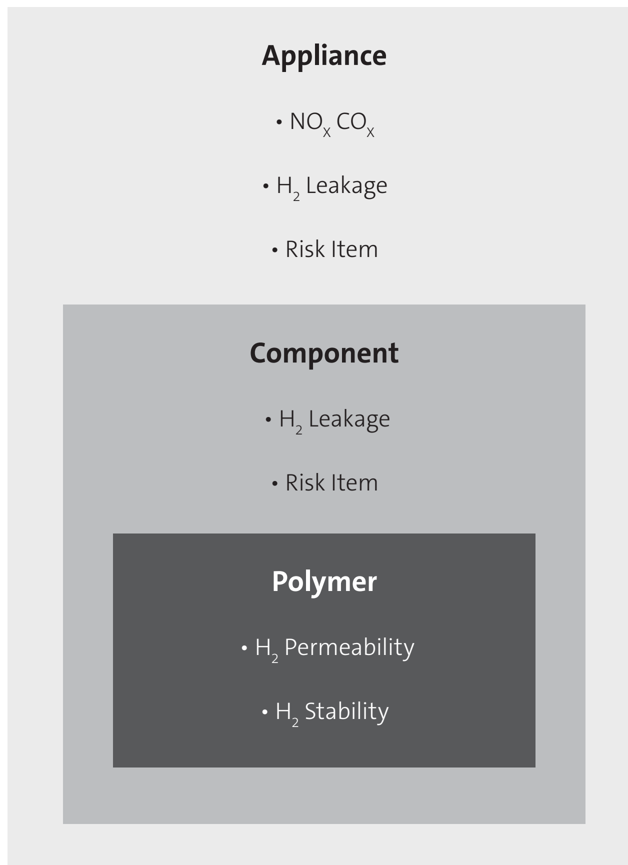

Figure 6: The concept of hydrogen compatibility assessment.

To learn more visit https://www.ul.com/services/hydrogen-integrated-system-services

Summary

For the pipelines themselves, it was found that hydrogen embrittlement was more of a concern for transmission pipelines than distribution pipelines, with the concern being its effect on steel pipes and not polymer pipes. With pipe materials in mind, it has been proposed that up to a 50% hydrogen-natural gas blend could be used by adapting the Integrity Management Program.[26] However, it was found that it is not the compatibility with the pipe materials that would likely be the limiting factor for what percentage of hydrogen can be delivered using natural gas pipes.

Risk factors, which consider the probability of hazards and their severity, were evaluated for a variety of different hydrogen-natural gas blends and compared to those of natural gas. At every level of hydrogen addition, it was found that risk factors increased. This was most severe for service lines, which are in closest proximity to human lives, due to the potential for gas to build up and detonate. Under 20% hydrogen, the increase in risk factor was moderate, but at higher concentrations, the increase in risk factor was judged as severe. With that in mind, GTI has stated that up to 20% hydrogen can be used without a significant increase in risk.[7] NREL used this same data, but chose 15% hydrogen as a maximum blend percentage,[37] apparently to be more conservative.

When considering polymers, the most pertinent concern is over leakage at joints and valves in various points throughout the system, particularly in service lines and appliances. This is due to the increased permeability of hydrogen due to it being a much smaller molecule than a natural gas molecule (namely the methane molecule). The stability of a polymer may also be in question due to this increased permeability. A hydrogen compatibility test is proposed as an extension of UL 746A.

Also pertinent to appliances is making sure that they can operate at the correct temperature without the risk of flame-back, accelerated oxidation and degradation of parts due to increased temperatures near surfaces, and meet emission standards. Some testing has indicated that a hydrogen blend of up to 20% can be used with appliances without notable negative effects.[51] To determine appliance capability, test methods comparable to those used in UL 25 are proposed to show the materials used are suitable as well as additional testing per end-product standards to address any hazards for their product type.

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