Technical Considerations for Widespread Development of Hydrogen Infrastructure

Being a clean emission free fuel, hydrogen is commonly referenced as a key component of the Energy Transition, providing an option for decarbonisation of hard-to-abate sectors including some forms of transport and also space heating.

Forecasts across the energy sector suggest a rapid and large expansion of hydrogen production, transportation and utilisation. However, commentators to date have bypassed discussion of the detailed technical requirements of such a large hydrogen industrial roll-out.

In this article, we will review some key practical elements of the hydrogen roll-out to explain some of the complexities that need to be mitigated for large scale hydrogen market development.

Low Energy Density

Hydrogen gas when transported and stored at similar physical conditions (pressure and temperature) to natural gas has approximately 3 times less energy density. Hydrogen has a very high gravimetric energy density (~120 MJ/kg; methane is ~50 MJ/kg) but a poor volumetric energy density (MJ/m3) when compared with other fuels.

This is one reason why hydrogen has struggled to gain traction in the lighter-weight transportation sector - the relative ratio of hydrogen storage volume to vehicle size. For heavier vehicle transportation sectors, volume to vehicle size ratio is reduced, making the fuel more practical.

The hydrogen market is still relatively immature and technological progress in terms of transportation fuel and power utilisation is expected to advance rapidly. Material-based hydrogen storage systems including adsorbents, liquid organic compounds, hydrides and other hydrogen containing chemical species will reduce in cost, following solar, wind and battery technology trends.

Utility pipeline transportation of hydrogen in replacement of natural gas, as proposed in a number of natural gas to hydrogen repurposing projects, is viable as hydrogen has a similar overall energy density to that of methane, as explained later.

Utility Scale Storage of Hydrogen

The most common utility-scale existing underground gas storage (UGS) sites for hydrogen are developed salt caverns, utilised at a handful of refining and industrial chemical facilities globally (namely 3 sites in Texas and Teesside in the UK). Salt caverns are constructed by dissolution of the core of the salt formation through controlled water injection and salt removal (as brine) to form the cavern. Salt caverns have been widely used to store both natural gas and gaseous chemicals; they also provide a controlled environment, as they contain limited water and minimal contaminants.

The potential future utility-scale storage of high-purity hydrogen for refining, industrial or fuel cell applications, in a depleted gas reservoir or aquifer, has been widely discussed but is still yet to become a reality. No depleted gas reservoir has yet been commercially developed to store high-purity hydrogen, although a small number of aquifers (as well as salt caverns) have at some stage stored mixed gases of up to about 50 percent hydrogen, typically for domestic town/manufactured gas type duties.

Obviously the UGS of natural gas (methane) is commonplace and much of the technological basis for natural gas UGS would be applicable to hydrogen UGS. However there are some specific aspects of high-purity hydrogen UGS that need to be considered:

Contamination and Impurities

High-purity hydrogen stored in a depleted reservoir or aquifer would suffer from significant contamination through exposure of hydrogen to fluids in the reservoir, predominantly water and methane.

The commerciality for high-purity hydrogen UGS underground is therefore dependent on required withdrawal-cycle hydrogen composition and the costs associated with required gas processing for impurity removal. Lower-purity hydrogen UGS may have more potential, for uses where mixed methane-hydrogen streams (or streams with acceptable levels of contaminants) have a market.

Reservoir Integrity

There do not appear to be any additional reservoir integrity issues by considering hydrogen instead of methane under the same pressure and temperature regime in a depleted gas reservoir. The existing cyclic pressure influence on cap-rock integrity identified and modelled in the context of natural gas UGS will be the same in hydrogen service.

Hydrogen is less viscous and has a higher diffusivity than methane. The lower viscosity could impact on differences in, for example, skin formation at the wellbore over multiple cycles and relative movement of gas and water in reservoirs with active aquifers, which could cause reduced voidage efficiency. However good engineering design should be able to compensate for this.

The higher diffusivity of hydrogen may increase gas losses through the cap rock by diffusion, although hydrogen also possesses extremely low solubility in water, so diffusion rates would be limited by the presence of water in the cap rock. Likewise the dissolution of hydrogen in the existing reservoir fluids up to equilibrium would cause some hydrogen losses but these are likely to be generally inconsequential volumetrically. Data from town/manufactured gas aquifers suggests that diffusivity does not have a significant impact although the data group is statistically small.

As with all UGS projects, subsurface modelling of the reservoir and its integrity would be an essential pre-requisite of a Field Development Plan.

Geochemistry & Microbial Activity

In terms of geochemical interaction, the limited academic materials tend to a position where hydrogen has limited direct geochemical interaction subsurface due to its atomic nature, however microbial induced reactions have been reported as potentially significant.

Subsurface reservoirs contain microbes, either autochthonic (naturally present) or anthropogenic (introduced by drilling). Reservoir souring by microbes has been a common problem for many existing hydrocarbon projects. Similar microbial processes are likely in UGS hydrogen reservoirs; microbial conversion of hydrogen to methane in addition to souring has also been reported in some of the historic town/manufactured gas reservoirs mentioned earlier to relatively significant levels.

Microbial activity can be curtailed or eliminated where subsurface temperatures are sufficiently high, or through specific chemical injection, although microbial adaption including growth of thermophilic colonies cannot be ruled out. The range and depth of academic research in this area is limited and therefore there is uncertainty as to the risks to a hydrogen UGS facility, hence further microbiological assessment of any proposed storage site would be required.

Well Design

Well designs for hydrogen UGS duties are most likely to be similar to those for natural gas UGS and therefore not considered a major concern in terms of mechanical design. However, the metallurgical impact of high pressure hydrogen on well elements such as the casing and tubing steel alloys, cement, packers and seals will need to be assessed. Oil Field Service companies, which are likely to be the main providers of equipment and services to the hydrogen UGS development market, will need to test and certify their equipment to high hydrogen partial pressures.

Surface Facility Process Design

The key technical issues for hydrogen UGS that will need to be considered include suitable compression and surface treatment facilities, especially if the surface facilities are expected to operate both, or a mix of, methane and hydrogen fluids such as in lower-purity hydrogen duty. Although a surface facility review would be required, two areas of likely engineering focus for lower-purity hydrogen handling are:

- The capability of any compressor (especially turbo-machinery) to operate satisfactorily both on methane and hydrogen-rich streams. Process equipment designed for use for a methane-handling system can have a significantly different design basis to hydrogen-handling systems. For example, compression ratios will be different if using the same compressor under hydrogen service versus methane service.

- Metallurgical requirements and design codes to handle both methane and hydrogen-rich streams.

For higher-purity UGS hydrogen, surface facility design parameters would likely be simpler than lower-purity streams since the operating design envelope would be narrower, although high-purity hydrogen service at large throughputs is a specialist area of turbo-machinery supply. High-purity surface facilities would still require consideration of aspects such as metallurgical specification.

Rotating Equipment

Gas turbines are a significant part of gas industry process facilities, being a high cost component in addition to being technically complex. Gas turbines designed for natural gas are already technologically advanced through development over many years. Design for high hydrogen-content process streams has been ongoing by many of the industry's main players for a number of years, although the recent focus on hydrogen's potential rapid growth in the power sector has re-energised the likes of Mitsubishi Hitachi Power Systems, Siemens, GE and Ansaldo to push hard on advanced concepts for combustion of up to 100 percent hydrogen streams.

Through the European industry trade body, EU Turbines, all aligned manufacturers committed to providing for up to 20 percent hydrogen fuel mixes by 2020 and for operation on 100 percent hydrogen fuel by 2030. The manufacturers all report significant progress with developing new high hydrogen fuel content turbines, although the existing global power sector gas turbine stock would require significant retrofitting to handle high hydrogen service beyond a 5-20 percent range. The costs involved with such a large-scale industrial sector retrofit will only be considered commercial when there is clear guidance from regulatory authorities that plans for high hydrogen content gas grids were irreversible.

High hydrogen fuel content turbines also require consideration of minimising high NOx emissions, and the design also needs to be able to compensate for higher flame speeds compared to natural gas (and potential combustion oscillation) and a hotter flame. Continued advances in Dry Low Emission (DLE) technology are therefore a pre-requisite for high hydrogen fuel content turbine development.

The compression of hydrogen in a centrifugal compressor is more difficult than for methane. Although such compressors have been in hydrogen service in the refining and petrochemical sectors for years, they tend to operate with a degree of inefficiency due to the low molecular weight of hydrogen. The compression ratio is proportional to the molecular weight hence hydrogen requires a significantly larger compressor for the same compression ratio versus methane. Likewise in hydrogen service, the impeller can approach the mechanical strength limit of the blade, given the required blade tip speed. Reports suggest that 10 percent hydrogen in natural gas can be handled in an existing compressor without significant concern, but any higher than this requires the retrofitting of elements of the compressor, and beyond 35-40 percent the compressor requires replacement. Reciprocating compressors are reportedly more efficient for hydrogen service than centrifugal compressors although required utility-scale capacities are an issue for reciprocating systems.

Metallurgy and Hydrogen Design Standards

Operating envelopes and the effect of co-produced components in any hydrogen stream will require a detailed metallurgical assessment for the process equipment and pipelines under all operating design conditions. Metallurgical compatibility of the process stream under hydrogen service, particularly combined with water partial pressure conditions, would require careful analysis. Hydrogen-induced embrittlement is a known phenomenon but exact effects and conditions would need to be carefully assessed.

A conversion of infrastructure designed to one set of standards and codes, and changing the fluid service, will likely require significant engineering and regulation reviews.

There are a number of internationally recognised codes and standards. However for hydrogen service, compliance with ASME B31.12 code, Hydrogen Piping and Pipelines, would typically be required.

Existing natural gas transportation pipelines would likely be already designed to ASME B31.8 (and API 5L) standards and as such modification of natural gas systems to higher or full hydrogen service would need to consider requirements of ASME B31.12. Likewise existing process facilities modified to higher hydrogen content would need to be checked against both ASME B31.3 and B31.12 depending on process conditions.

Reported research has shown that hydrogen embrittlement, caused by high hydrogen fluid percent composition, appears to be generally limited at lower temperatures (sub 400F/204C). However at higher temperatures, such as those found in some process equipment and heat exchangers, high temperature hydrogen attack (HTHA) is a recognised issue; the API updated API RP941 includes for material specification at high temperature hydrogen service.

Pipeline Transportation

Hydrogen injection into natural gas networks is an obvious option for a contribution to overall decarbonisation. Historically, hydrogen as a component of town gas, has been a very small part of the energy mix in the early 20th century in a number of countries.

Research is widespread relating to acceptable concentrations of hydrogen in natural gas pipelines and a number of countries acknowledge concentrations in the range of 5-10 percent by volume as being acceptable. However, appliances designed for natural gas would require some modifications or re-design to go much above this threshold. Permitted concentrations of hydrogen admixtures in the current European gas pipeline network vary between countries from zero to 20 percent. It is recognised that common admixture concentrations cannot be set for the entire European network due to the localised requirements. The US is also in pilot phase of testing hydrogen admixture levels in gas grid supplies.

Similar Energy Densities Can be Transported

Although hydrogen has a significantly lower (about one third) volumetric energy capacity (MJ/m3) than methane, it also has significantly lower density and viscosity than methane. Hydrogen therefore exhibits lower pressure drops for similar operating conditions than methane. Hence for infrastructure-type pipeline transport with a typical pressure profile from inlet to destination, a hydrogen stream would carry only a small reduction (10-20 percent) in energy density than a methane stream.

As already mentioned, hydrogen will have an impact on fracture embrittlement of carbon steel, which will require specific bespoke analysis to assess the impact on pipeline longevity. Furthermore, the ancillary equipment required such as valves, regulators and control systems relies on gaskets, membranes and seals, which again will require evaluation in co-ordination with the required codes and standards relating to suitability in hydrogen service.