What are the risks, safety, or legal hurdles of using hydrogen?

The types of risk and safety implications for hydrogen are the same as for natural gas; both can be flammable or explosive. Hydrogen is significantly lighter than natural gas, so in any ventilated area it will much more quickly, and is therefore usually less dangerous than natural gas. However, its explosive limits are wider than for natural gas, so if it does get trapped in a confined space it can cause a larger explosion.

The legal hurdles will need to be addressed. Most countries have fairly stringent regulations on the allowable composition of gas that may be transported in transmission or distribution lines (e.g. the UK Gas Safety Management Regulations), and currently these compositions explicitly prohibit hydrogen.

What skills do we need to help with the transition?

I think, the major skills required are a sound foundation and understanding of basic/fundamental science and engineering. Trained and competent metallurgists, mechanical engineers, pipeline engineers etc. should be able to apply their knowledge to the specific requirements of hydrogen.

The majority of natural gas pipelines in the local gas distribution and transmission network (7-70bar) are X52 and below and operate <30%SMYS.

According to our ROSEN Integrity Data Warehouse, ~57% of lines in the UK are X52 or below and operate at <30% SMYS, so I agree with this statement for the UK. However, worldwide, only ~15% of lines are X52 or below and operate at <30% SMYS, meaning that ~43% of lines in the UK, and ~85% of lines worldwide are either higher grade or operate at a higher utilization factor, or both.

Can you utilize an HDPE liner with a carbon steel carrier pipe to be able to get the higher MAOP needed?

The whole question of liners and internal coating is an interesting one. Currently, there is no allowance in the codes for the use of a liner. In theory, the liner should reduce the effect of hydrogen by inhibiting access to the pipe wall. However, gaseous hydrogen can permeate through HDPE, so you may end up with pockets of high pressure hydrogen between the liner and the carrier pipe. As with any barrier-type approach, the effectiveness of the liner/coating depends on it being completely coherent and free of gaps or holidays, which could be an issue in the case of girth welds, or damage being introduced in service (erosion or damage by an inspection tool).

ISO 15156 has the SSC domain diagram. Do you think a similar approach to defining zones/regions relative to partial pressure of H2 would be a worthwhile endeavor?

The domain diagram approach is something that could potentially be very powerful and very useful. One of the major benefits of the ISO 15156 approach is that it uses a simple to measure value (hardness) as a proxy for material behavior and allows SSC susceptibility to be assessed based on this value and the environment (H2S partial pressure and pH). The analogy for this would be to base it on the partial pressure of gaseous hydrogen. This approach is definitely desirable, unfortunately for gaseous hydrogen I do not think there is sufficient research available yet to define whether hardness is a suitable measure or whether there is an alternative simple property which could be measured.

Is ROSEN thinking about an industry pivot and green ammonia takes center stage, which is made with hydrogen that comes from water electrolysis powered by alternative energy?

I think the entire industry is thinking about an industry pivot towards decarbonization. Currently, most of ROSEN's thinking has been around gaseous hydrogen as the energy vector; however, we are not ruling out ammonia. It should be noted however that ammonia itself has its own characteristics and potential threats (e.g. caustic SCC).

You have mentioned existing gas pipelines, but what about existing oil pipelines? Is the approach essentially the same?

The approach is essentially the same, but there will be additional aspects to take into account around the transition from liquid to gas service. From the integrity point of view, one potential difference could be the condition and cleanliness of the internal pipe surface of an oil line compared to a gas line.

Is there a movement to prepare a "conversion guideline: from gas/oil to H2" like it exists for gas to oil?

This is a very hot topic in the industry. Currently, ASME B31.12 Section PL.3.21 offers guidance on the conversion to hydrogen, as outlined in the AIGA/EIGA guidelines. However, I think there are various issues within these guidelines that make them difficult to apply (e.g. the requirement for destructive sampling once per mile). IGEM in the UK and DVGW in Germany are also working on, or have already released, guidelines but these both refer back to ASME B31.12. In addition, there are various JIPs starting up, and ROSEN is currently working with the European Pipeline Research Group (EPRG) with a view to develop some guidance.

A hydrogen pipeline, if transported through long distance, may miss surveillance at some point, where it may leak, and as it expands, it will get heated up and explode. How do we address such a risk?

Monitoring and inspection of leakage in long pipelines is definitely an issue, but it is not specific to hydrogen. This threat already exists for natural gas, and the integrity management approach should be the same for hydrogen.

Are the "safety distances for major accident hazards" to occupied buildings etc. more onerous for H2 compared to natural gas?

The detailed answer to this will depend on the codes/applicable regulations, but the short answer is probably yes.

Any research on installing a liner or internal coating to offset hydrogen ingress into the steel?

I suspect there is, but I am not aware of any specifics. Liners and coatings cannot currently be taken into account according to existing codes, and there are certain practical concerns about how to retrofit and ensure complete coverage of the entire internal surface (including welds) without damaging the liner.

On the downstream applications, how does hydrogen contribute to our current and forecast energy needs? Power generation?

Various different ways, I would recommend the Hydrogen Council website https://hydrogencouncil.com/en/ as a good resource to learn more.

Are the markets conditions given for the transition?

In my opinion currently no, the main reason why hydrogen has not yet taken off is that the economic conditions are not in place yet. However, there is a clear and defined political will behind the transition, and some major companies with very deep pockets are taking a keen interest. As the technology develops, the production costs of hydrogen will inevitably drop, and with the political will the economic landscape can be tailored to suit through the use of taxation, incentives, subsidies etc. About a year ago, I had a similar discussion and asked whether the hydrogen transition was inevitable. At the time, the answer was that it was definitely not and that the main risks lay in changes in the political landscape. That risk is still there, but I think there has now been so much movement and momentum behind hydrogen that the market conditions will adapt.

I believe it is not only about mechanical properties, the whole pipeline system needs to be assessed (leak detection, sealing, measurement, compression ...)

I very much agree, we need to recognize that hydrogen can be safely managed and transported, but it is not the same as natural gas and will need to be treated as such.

Which in-line inspection tool do you recommend for H2 pipe?

Tool selection really depends on which threats you are looking for. In general terms, I think the major concerns associated with H2 pipes are the material properties and the risk of cracking, therefore I would normally recommend a crack detection tool (e.g. ROSEN's EMAT technology) and a materials properties tool (e.g. ROSEN's RoMat PGS service).

What would be the increase in in-line inspection (ILI) frequency beyond current hydrocarbon requirements?

Differences in frequency have not yet been defined. In general terms, it would appear prudent to increase the frequency of inspection immediately after conversion but the level of increase would need to be considered on a case by case basis.

Can you explain basic corrosivity of hydrogen gas, at the ATOMIC vs. MOLECULAR level?

Molecular hydrogen is not particularly corrosive, but problems can occur at the pipe surface when the molecular hydrogen dissociates into atomic (or ionic) hydrogen through Sieverts' law. This atomic hydrogen is absorbed into the pipe wall and will diffuse into areas of stress concentration, leading to various issues. A full explanation of how this happens would fill several books and is beyond my competence anyway, but there are various competing acronyms and mechanisms (e.g., HELP – hydrogen enhanced local plasticity and HEDE – hydrogen enhanced decohesion).

Depending on the source of hydrogen (more or less greener), the use of pipeline might often vary (blend, no blend, etc.)... Is this accounted for, especially in terms of ILI and risk assessment?

The question of blends is interesting. Most companies are currently talking about blends as an interim step on the way to 100% hydrogen; however, others are talking about moving straight to 100% hydrogen. In terms of blends, the important factor is the partial pressure of hydrogen, not the percentage, this will need to be taken account of.

Natural gas has higher chemical potential energy, quite a bit higher than H2.

The energy carrying characteristics of natural gas are different from H2, and to maintain the same energy throughput, the flow through the pipeline will have to change. The exact extend will be determined by the energy requirements and flow characteristics, but it is fair to say that flow rate and operating pressures will probably have to increase, if the same energy throughput is required.

Pipelines are going through very hot and very cold zones. Any particular heat effect on H2 transportation?

There are various heat-related effects, not only from the ambient environmental temperature but also from the fluid temperature. Currently, the codes do not really reflect this. The limited data available implies that the effect will be relatively small due to "normal" operating temperatures. However, more research is probably needed to quantify this.