Knowledge gaps in the risk assessment of hydrogen and carbon dioxide pipelines

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1 ABSTRACT

There are several UK Net Zero projects at the planning stage that involve the construction or repurposing of transmission pipelines for the transport of hydrogen and/or carbon dioxide (CO_2). These include two hydrogen and Carbon Capture and Storage (CCS) cluster projects, HyNet North West and the East Coast Cluster, which aim to be operational by the mid to late 2020s.

The Health and Safety Executive (HSE) is the statutory authority in Great Britain responsible for providing public safety advice to planning authorities on the risks associated with proposed new developments (e.g., housing, schools, hospitals) near major hazards sites and major accident hazard pipelines. For natural gas pipelines, HSE and UK pipeline operators make use of well-established methods for assessing risks that are based on validated models and statistical data on failure rates stretching back several decades. Hydrogen and CO_2 transmission pipeline networks do not yet exist in the UK or Europe, and so there is a lack of this operational data from which failure rates can be derived. There are also significant differences in properties between natural gas, hydrogen and CO_2 that affect the risk calculations. For hydrogen pipelines, specific issues include:

- How fracture mechanics models need to be adapted to take account of the effects of hydrogen on mechanical properties of different grades of pipeline steels
- Assessment of the fire and explosion consequences
- Selection of suitable ignition probabilities for each part of the event tree

For CO_2 pipelines, issues include:

- Response of the pipeline material to external interference and its effect on failure rates
- Potential for internal corrosion under different CO2 conditions and its effect on failure rates
- Modelling release rates from dense-phase CO_2 pipelines
- Effect of terrain on the dispersion of CO_2 from pipeline releases

This paper discusses the progress made to date internationally in addressing these issues together with areas that could benefit from knowledge sharing and/or collaboration across organisations.

2 INTRODUCTION

The UK government has committed to achieving NetZero by 2050. To meet this target there are a number of proposed trials that involve the construction or repurposing of transmission pipelines to transport either hydrogen to the distribution network or captured carbon dioxide (CO_2) to offshore storage. These include two hydrogen and Carbon Capture and Storage (CCS) cluster projects, HyNet North West[1] and the East Coast Cluster[2], which aim to be operational by the mid to late 2020s.

The Health and Safety Executive (HSE) is the statutory authority in Great Britain responsible for providing public safety advice to planning authorities on the risks associated with proposed new developments (e.g., housing, schools, hospitals) near major hazards sites and major accident hazard (MAH) pipelines, such as the natural gas transmission network. For natural gas pipelines, HSE and UK

[1] https://hynet.co.uk, accessed 12 January 2023

[2] https://eastcoastcluster.co.uk/, accessed 12 January 2023

pipeline operators make use of well-established methods for assessing risks that are based on validated models and statistical data on failure rates stretching back several decades. Hydrogen and CO_2 transmission pipeline networks do not yet exist in the UK or Europe, and so there is a lack of this operational data from which failure rates can be derived. There are also significant differences in properties between natural gas, hydrogen and CO_2.

3 COMPARISON OF HYDROGEN AND CO_2 PROPERTIES TO NATURAL GAS

To understand some of the issues associated with the transportation of hydrogen and CO_2 by pipeline, it is necessary to understand the properties of the two substances. These are shown in Table 1, together with those for methane (the main component of natural gas), which make up the majority of the MAH pipelines in Great Britain. The table indicates that there are significant differences in the properties of each substance.

Table 1 Comparison of properties of methane, hydrogen and carbon dioxide

	Methane, CH_4	Hydrogen, H_2	Carbon Dioxide, CO_2
Molecular Mass (g/mol)[a]	16.043	2.016	44
Density (kg/m^3)*[a]	0.68	0.08	1.9
Density relative to air*	0.55	0.07	1.5
Diffusivity in air (cm^2/s)	0.196	0.611	0.138
Dynamic viscosity (Pa.s)*[a]	1.1×10^{-5}	8.7×10^{-6}	1.4×10^{-5}
Specific heat capacity at constant pressure (kJ/kg.K)*[a]	2.2	14	0.8
Ratio of specific heat capacities (γ)*[a]	1.3104	1.4069	1.3
Lower flammable limit (% v/v)[c]	4.4†	4.0†	N/A
Upper flammable limit (% v/v)[c]	17†	77†	N/A
Lower detonation limit (% v/v)[e]	6.3	18	N/A
Upper detonation limit (% v/v)[e]	13.5	59	N/A
Detonation cell size (mm)[e]	250-310	15	N/A
Stoichiometric concentration (% v/v)[b]	9.4	30	N/A
Auto-ignition temperature according to EN14522 (°C)[a]	595	560	N/A
Minimum ignition energy (mJ)[b]	0.26	0.01	N/A
Minimum quenching distance (mm)[b]	2.0	0.5	N/A
Burning velocity (m/s) ‡[b]	0.37	3.2	N/A
Maximum Experimental Safe Gap, MESG (mm)[c]	1.12	0.29	N/A
Minimum Igniting Current (MIC) ratio[c]	1.0	0.25	N/A
Energy density per unit mass[d] (MJ/kg)	56	142	N/A
Energy density per unit volume[d] (MJ/m^3)	40	13	N/A
Temperature Class[c]	T1	T1	N/A
Equipment Group[c]	IIA	IIC	N/A
Toxic?	No	No	Yes

* Properties given at 15°C and ambient pressure

† The lower and upper explosive limits for methane and hydrogen are given slightly different values in different sources in the literature. For example, some sources[a,b] quote the LEL and UEL for methane as 5.0% and 15% by volume in air (v/v), and UEL for hydrogen as 75% v/v.

‡ Slightly different values are quoted in the literature for the burning velocity, e.g. Harris (1983) gives the methane and hydrogen values as 0.45 m/s and 3.5 m/s.

[a] https://encyclopedia.airliquide.com, accessed 10 January 2023,

[b] Drysdale (1998)

[c] BS EN 60079-20-1:2010 (BSI, 2010)

[d] https://www.engineeringtoolbox.com/fuels-higher-calorific-values-d_169.html, accessed 10 January 2023

[e] Babrauskas (2003)

[f] Roberts (1963)

Of particular note for hydrogen is the size of the molecule when compared to methane, together with its much wider flammability range, lower minimum ignition energy and faster burning velocity. CO_2, on the other hand, is toxic and, in dense phase, is conveyed at pressures that are generally greater than those for natural gas.

Toxicity can be measured by the dangerous toxic load (DTL). The DTL describes the exposure conditions in terms of both the airborne concentration and duration of exposure that produce a particular level of toxicity in the general population. CO_2's toxicity is highly non-linear meaning that doubling the concentration leads to a 256 increase in the DTL. Fluctuations in concentrations that occur naturally in dispersing turbulent clouds are therefore important (Gant and Kelsey, 2012).

CO_2 is also denser than air, both in gaseous and dense phase, and releases will therefore generally remain close to the ground.

4 HYDROGEN

Molecular hydrogen in gaseous form can dissociate into atomic hydrogen on metal surfaces, the small size of the atom facilitating its migration into the metal lattice where it can lead to hydrogen embrittlement. While there are many different terms used to describe hydrogen embrittlement in steels, ultimately, this manifests itself as a reduction in certain mechanical properties such as ductility, toughness and fatigue resistance. This is a key consideration which may limit the repurposing of steel pipelines, with factors such as strength and steel microstructure having an effect on sensitivity. Higher strength pipeline grades in particular can show an increased sensitivity to the effects of embrittlement.

The much wider flammable range, lower minimum ignition energy and greater flame speed of hydrogen, when compared to methane (or natural gas), mean that hydrogen will ignite much more readily over a much wider range of concentrations and any ignition will more readily progress to detonation. This means that the risks associated with hydrogen pipelines will vary when compared to those for natural gas.

From a calculation of risk perspective, these differences mean potentially higher failure rates, higher ignition probabilities and the possibility of explosions, which are not currently considered for the natural gas transmission system in Great Britain.

4.1 GAPS IN HYDROGEN KNOWLEDGE

Although hydrogen pipelines do exist, there is a lack of operational experience, particularly when compared to the decades of experience with natural gas. There are approximately 2,200 km of hydrogen pipelines in the USA and 1,600 km within Europe, but in comparison there are approximately 22,000 km of high pressure natural gas pipelines that have been operating for over 40 years in the UK alone.

There is also limited experimental data at the scales that are of relevance to hydrogen transmission pipelines. There have been two large-scale, 60 bar hydrogen pipeline experiments (Action *et al*., 2010) and there were the NaturalHy experiments, which considered natural gas and a 20% blend of hydrogen in natural gas at pressures of approximately 70 bar (Lowesmith and Hankinson, 2013). These experiments provided some information about ruptures of hydrogen pipelines, e.g., information on release rates and the size of subsequent fires, but several questions remain.

In terms of calculating risk from high pressure hydrogen pipelines, the remaining gaps in knowledge are believed to be as follows:

Failure rates

Although there has been research conducted in recent years to investigate the effects of hydrogen on various grades of steel, there is still some uncertainty over exactly how the material will respond to long term exposure at typical pipeline pressures. Findings so far indicate:

1. The strength properties of pipeline steels reviewed to-date do not appear to be significantly affected by testing in hydrogen gas. The effect on elongation to failure, however, was found to be significant. This is linked to the diffusion-limited mechanism of hydrogen embrittlement.
2. Fracture toughness is reduced for most pipeline steel grades under both gaseous hydrogen and cathodic charging conditions. The average retained toughness for pipeline steels up to grade X65 in the literature was 0.54 times the original value for initiation toughness. The effect on tearing resistance was greater, as fresh metal surfaces are created in this test, enhancing hydrogen uptake. The greatest effect on toughness was observed between 0 bar and 20 bar hydrogen pressure, with diminishing rates of degradation at higher pressures.
3. There is limited data in the literature on the effect of hydrogen environments on S-N fatigue behaviour of pipeline steels. What there is existing data it suggests that the number of cycles to crack initiation is reduced by a factor of 3-10 in low strength grades.
4. Some studies indicate that the theoretical net fatigue life in the presence of hydrogen is 10-100 times less than that in natural gas. The greatest effect is on the crack growth rate, with tests across all grades showing this parameter to be highly sensitive to the presence of hydrogen. The effect is sensitive to impurities in the gas and the cycling frequency.
5. The effect of hydrogen on the resistance of steel pipe grades to fast running fractures has not been evaluated. Charpy impact and drop weight tear test (DWTT) parameters can be used in fracture control models for natural gas, but data on the effects of hydrogen on these parameters is limited. For rapid crack propagation, however, hydrogen will decompress faster than methane, giving a reduced driving force for fracture propagation.

In many of the above areas, a number of studies are progressing to address the research gaps. This includes further fracture toughness and fatigue testing within the HyDeploy project[3] and testing in hydrogen on full-scale assets extracted from the UK network and re-assembled as an above-ground off-line test facility within the "Futuregrid" project[4].

Compilation of materials test data in gaseous hydrogen from the many ongoing worldwide test programmes would benefit the entire industry, as would standardisation of test conditions to represent those of the gas network.

The uncertainties highlighted and lack of experimental data mean that there could be a significant degree of inaccuracy in the generation of failure rates that rely on fracture mechanics in their calculation. In Great Britain, these methods are used to calculate failure rates from third-party activity, i.e., when objects such as diggers strike the pipeline. Although the likely frequency of these events is known, as this is unlikely to be changed by a move to hydrogen, the likely material response and subsequent failure frequency is less clear. Furthermore, the presence of hydrogen may also affect the rate of other failure modes or introduce new ones. The lack of long-term operational data means that any method employed in the failure rate calculation cannot be easily validated.

In Great Britain, failure rates for other causes such as mechanical, corrosion and ground movement are currently based on historical operational data. These are less likely to be affected by the presence of hydrogen and so the continued use of natural gas data is not seen as being inappropriate.

Fire and explosion

Currently in GB, Vapour Cloud Explosions (VCEs) are not considered for high pressure natural gas transmission pipelines as the risk is dominated by fires. The higher flame speed of hydrogen, however, means that there is potentially an increased likelihood of a hydrogen release leading to an explosion with associated overpressure effects. This has been observed in a limited number of jet release experiments and a model for predicting vapour cloud explosion overpressures has been proposed (Miller *et al.*, 2015; Jallais *et al*., 2017). However, there is limited information available to determine whether this increase in risk from potential VCEs is significant when compared to the effects of the potential fires. It is also only likely to occur in the case of delayed ignition, which may not be a credible event for transmission pipelines, given the low ignition energy for hydrogen. If it is, then explosions will need to be modelled as part of a transmission pipeline risk assessment.

Experimental work is planned in the UK to investigate this issue as part of the ongoing National Grid "FutureGrid" project.

Ignition probability

The larger flammable range and lower minimum ignition energy of hydrogen compared to natural gas means that a release is more likely to ignite. HSE reviewed ignition probabilities for use in the event trees that it uses for pipeline modelling some years ago (McGillivray, 2015) and derived probabilities for substances with low minimum ignition energy. However, there is always a great deal of uncertainty around ignition probabilities and the previous work did not identify any hydrogen-specific data,

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[3] www.hydeploy.co.uk, accessed 23 January 2023.

[4] https://www.nationalgrid.com/gas-transmission/document/139131/download, accessed 17 January 2023.

although hydrogen was considered in the analysis. HSE is updating this work to specifically consider hydrogen and to determine if any new information has become available in the intervening years.

5 CO_2

One of the main differences between CO_2 and natural gas is that it is toxic and non-flammable. It is also denser than air, which means that, even if the initial release is vertical, the resulting cloud is likely to subsequently slump to the ground.

Two of the main considerations for steel pipelines carrying CO_2 are potential corrosion due to presence of water in the gas stream and, in the case of dense-phase CO_2, the arrest of long-running fractures.

From a risk perspective, these known differences with CO_2 mean that there could be potentially larger failure rates, when compared to natural gas, and the risks could also extend further from the pipeline.

5.1 Gaps in CO_2 knowledge

As in the case of hydrogen, there is relatively little operational experience of CO_2 pipelines. There are approximately 6,000 km of CO_2 pipelines globally. The majority of these are located in the USA and Canada and are used to transport CO_2 for Enhanced Oil Recovery (EOR). The CO_2 streams used for EOR may contain different impurities to the CO_2 captured through CCS, which may need careful consideration when evaluating failure rates. The EOR experience may therefore be of limited applicability to CCS.

There is also limited experimental data available at the scales of interest for transmission pipelines that cover all gaps in knowledge. DNV undertook some large-scale tests on an 8" dense phase CO_2 pipeline[5]. In the decade from 2007 to 2017, several large international projects were undertaken, funded by the European Union, the UK government and industry, including CO2PipeHaz[6], MATTRAN[7], COOLTRANS (Cooper and Barnett, 2014, Cosham *et al*. 2016), COSHER (Ahmad *et al*., 2015) and CO2PIPETRANS (Holt *et al*., 2015). Findings were also collated into recommended practice (DNV GL, 2021).

Some of the drivers for this research were initial concerns raised that accidental dense-phase CO_2 releases could produce significant amounts of solid CO_2 (dry-ice) which could have an erosive jet-cutting effect or produce large solid banks of dry ice, which would take a long time to sublimate (Connolly and Cusco, 2007). At the time, these concerns seemed valid, given that CO_2 is used for erosion jet cleaning and cutting, and that a CO_2 well-head blowout in Hungary in 1998 led to a bank of ice and carbon dioxide snow some 1.5 to 2 m thick[8]. Subsequent experiments at DNV GL Spadeadam

[5] https://www.dnv.com/oilgas/laboratories-test-sites/dense-phase-spadeadam-video.html#:~:text=The%20video%20shows%20a%20rupture%20of%20a%20buried%2C,mass%20outflow%2C%20crater%20formation%20and%20dense%20gas%20dispersion accessed 10 January 2023.

[6] https://cordis.europa.eu/project/id/241346/reporting, accessed 17 January 2023.

[7] https://research.ncl.ac.uk/mattran/home.html, accessed 17 January 2023.

[8] https://publishing.energyinst.org/__data/assets/file/0006/71394/Guidance-on-HA-for-onshore-CCS-installations-WEB-VERSION.pdf, accessed 10 January 2023.

sponsored by BP involved targets placed in the path of CO_2 jets, which did not show significant erosion effects. Shell also funded experiments at Spadeadam where CO_2 was discharged into a steel enclosure, which showed some limited deposition of dry ice and no significant erosion effects (Dixon *et al*., 2012). Full-scale pipeline rupture experiments (Cooper and Barnett, 2014; Di Biagio *et al*., 2017) produced some deposits of dry ice, but not significant deep banks, although they were limited-duration releases.

The effect of the lack of historical operational and gaps in the experimental data is that many of the inputs to a risk assessment will have a high level of uncertainty associated with them. The specific gaps in knowledge are discussed below:

Failure rates

The potential for corrosion of carbon steel pipes conveying CO_2 is highly dependent on the presence of free water in the gas stream forming carbonic acid. In the case of non-dry gas, the presence of any impurities in the CO_2, such as NO_x and SO_x can increase the likelihood of corrosion due to the formation of acidic conditions and hence lead to higher failure frequencies. Extensive reviews of the corrosion issues presented by CO2 in pipelines have been carried out by Barker et al (2017) and Xiang et al (2017). The nature of the impurities and their level will depend on the source of the CO_2 and application of any gas conditioning prior to it entering the pipeline. This, along with the reliability of methods for ensuring consistently dry gas, will need to be understood and taken into account.

Fracture propagation is another area that may impact significantly on failure rates. There are two characteristics of CO_2 that increase the likelihood of fracture propagation; the Joule-Thomson effects and the decompression behaviour of supercritical CO_2.

In the event of a gas decompression, the expansion of CO_2 from a region of high pressure to one of low pressure causes a rapid cooling of the gas and significant cooling of the pipe. Since ferritic steels undergo a ductile-brittle transition, the sudden cooling can change the fracture behaviour of the pipeline steel from ductile (to which it was initially designed) to brittle. The potential for fast-running brittle fractures may therefore be increased by the cooling effect of the CO_2 decompression. The properties of the original pipeline material determined to ensure resistance to such fractures under natural gas conditions with tests such as the Charpy impact test and the Drop-Weight Tear Test (DWTT), may be insufficient to prevent fracture would require further assessment to ensure fracture prevention under this rapid cooling regime.

The second characteristic is that the decompression behaviour of supercritical CO_2 at pressures above 74 bar leads to an increased risk of fast running fractures since the net decompression speed of the fluid is less than the fracture propagation speed along the pipe, due to the presence of a decompression plateau in CO_2. The presence of impurities in the gas also affects the decompression behaviour, making predictions of fracture arrest requirements complex. Hence, the issue of long running ductile fractures is of a higher concern in dense-phase CO_2 pipelines than in natural gas pipelines.

There has been greater investigation of the fracture behaviour of supercritical CO_2 pipelines than for gaseous CO_2. There is therefore greater uncertainty around what the fracture arrest requirements are for gaseous CO_2 than for dense phase CO_2. The development of an empirical model for fracture control in dense phase CO2 has been described by Michal et al. (2020), in which data from nine full-scale propagation tests on dense phase CO2 was used to calculate the minimum required Charpy impact energy for the pipe material. Regions of confidence in the model were also indicated in this work. Recent work on this topic has been published by Cosham *et al*. (2022), who reviewed the existing data and guidance published by DNV (2021). The ISO 27913 standard on this topic (ISO, 2016) is currently being revised[9]. Both the Cosham-2022 and Michal-2020 studies indicate that while modifications to existing fracture control models for CO2 pipelines can lead to predictions in line with observed test results, additional full-scale fracture propagation tests are required.

The above discussion makes it clear that there are gaps in knowledge around material behaviour and that there is therefore uncertainty in the appropriateness of methods for deriving failure rates for CO_2 pipelines, in both gaseous and dense phase. As has already been identified, there is also insufficient operational data to derive failure rates using historical information.

Modelling dense phase CO_2 releases

When CO_2 is released unexpectedly, in either gaseous or dense-phase, dry ice can be formed, although the degree to which this occurs is uncertain. This could partially block parts of the pipe, potentially leading to alterations in the release rate. Dry ice has occurred from accidental releases such as the well-head blowout in Hungary in 1988 but experiments have only seen small amounts of dry ice deposition, as mentioned earlier. There have also been reports that dry-ice has blocked pipeline blowdown valves in the open position[10].

Terrain effects

CO_2 is denser than air and is therefore affected by gravity. This means that a release of CO_2 will tend to follow the local terrain and accumulate in dips and hollows in the ground, particularly in low wind speeds. The effects of a CO_2 release could potentially be felt at larger distances from the pipeline (as compared to a natural gas release), as was demonstrated by the Satartia incident in the USA in 2020. In that incident, the CO_2 was released on sloping terrain and the cloud engulfed the village of Satartia approximately a mile (1.6 km) away from the release point. The natural release of CO_2 from a volcanic crater in Lake Nyos and the incident at the Menzengraben potash mine in 1953 provide further illustrations of how CO_2 clouds can be influenced by terrain (Energy Institute, 2010; Hedlund, 2012). In these two incidents, the releases took place in a valley and the surrounding hillsides constrained and influenced the direction of the toxic cloud. This is very much in contrast with natural gas releases, where the hazards are generally centred on the release point or in close proximity to it.

For risk assessment purposes there is hence a need to take terrain into account when modelling CO_2 releases. For very short lengths of pipeline, validated Computational Fluid Dynamics (CFD) could potentially be used. However, CFD is computer intensive with typical run times of an hour or more per simulation. Given the need to consider a range of release scenarios in different wind directions and weather conditions at regular intervals along the pipeline length, this makes CFD unfeasible for routine use. An alternative method is needed that is simpler, quicker to run and yet takes into account the effects of terrain.

Another related knowledge gap is the lack of experimental data to validate any model of terrain effects. Without this data, the accuracy of models cannot be established and therefore the risk assessment

[9] For details of the relevant technical committee ISO/TC 265, see https://www.iso.org/committee/648607.html, accessed 17 January 2023.

[10] https://www.huffingtonpost.co.uk/entry/gassing-satartia-mississippi-co2-pipeline_n_60ddea9fe4b0ddef8b0ddc8f, accessed 17 January 2023.

remains questionable. A set of large field-scale experiments are needed in which CO_2 is released on a range of slopes and/or hills. Models then need to be validated against this dataset.

6 CONCLUSIONS

The drive to reach Net Zero by 2050 introduces new and emerging risks that need to be considered in pipeline risk assessments. Existing risk models derived for natural gas pipelines are not entirely appropriate for determining the risks to people from high pressure hydrogen and CO_2 pipelines. Models currently used for natural gas have been developed over many years and are able to utilise data from decades of operational experience. This experience does not currently exist for either hydrogen or CO_2 pipelines. Moreover, the different physical properties of hydrogen and CO_2, versus natural gas, mean that new types of hazard and their consequences need to be considered.

This paper has highlighted the main gaps in knowledge. Previous relevant work has been reviewed and potential topics where further work is required have been identified. Internationally, there are significant efforts currently underway to develop hydrogen and CO_2 infrastructure. The scientific knowledge gaps identified here are from the perspective of GB pipelines regulations. Different risk assessment practices and codes are applied internationally. However, many of the scientific knowledge gaps are common to risk assessment methods applied in other jurisdictions (by regulators and/or pipeline operators). Given the international nature of current hydrogen and CO_2 developments, it would be beneficial if knowledge could be shared wherever possible. HSE is keen to collaborate with other organisations on this topic with the aim of working together to find solutions and, ultimately, to help achieve our collective target of Net Zero.

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