

HSE's assessment of the safety evidence for 100% Hydrogen Heating

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Glossary of Acronyms and Abbreviations

This is not a comprehensive list of all abbreviations and acronyms used, rather a list of frequently used ones broken up into sections. All acronyms including these will be referenced in full form through-out.

Technical Terms

AIV – Automatic Isolation Valve

ALARP – As Low As Reasonably Practicable

CFD - Computational Fluid Dynamics

CONIFER –Networks and Installations Fire and Explosion Risk

ECV – Emergency Control Valve

EFV – Excess Flow Valve

EUSE – End User Safety Evidence

FMEA – Failure Modes Effects Analysis

HAZOP/ HAZID – Hazard and Operability / Hazard Identification studies

HSC – Hazardous Substances Consent

ILI – In-line Inspection

IMRRP – Imposed Iron Mains Risk Reduction Programme

LDS – Local Distribution System

LNG - Liquid Natural Gas

LTS – Local Transmission System

MAOP – Maximum Allowable Operating Pressure

MOBs – Multiple Occupancy Building(s)

MRPS – Mains Risk Prioritisation System

NDE – Non-Destructive Examination

NHSA – National Hydrogen Safety Assessment

NO_x – Refers to both Nitrogen Monoxide (NO) and (NO₂) Nitrogen Dioxide

NTS - National Transmission System

OCTG – Oil Country Tubular Goods

PE – Polyethylene

PRI – Pressure Reduction Installation

PRUs – Pressure Regulation Units

PTFE – Polytetrafluoroethylene

QRA – Quantative Risk Assessment

RAG – Red Amber Green

SFAIRP – So Far As Is Reasonably Practicable

SSSVs – Subsurface Safety Valves

TRL – Technology Readiness Level

UGS – Underground Natural Gas Storage

UHS – Underground Hydrogen Storage

Organisations

API: American Petroleum Institute

DESNZ: Department for Energy security and Net Zero

DNV: Det Norske Veritas

EU: European Union

GB: Great Britian

GDN: Gas Distribution Network(s)

HAS: Hazardous Substances Authority

IEA: International Energy Agency

IGEM: Institute of Gas Engineers and Managers

IOGP: International Association of Oil and Gas Producers

NGN: National Gas Networks

SGN: Scottish Gas Network

Section 1. Executive Summary

Introduction

The Health and Safety Executive (HSE) is Great Britain's independent national regulator for workplace health and safety. HSE's mission is to protect people and places. HSE's remit includes regulating to protect people against ill health, injury or death from work activities in Great Britain.

As part of supporting the UK government's net zero targets, HSE has been asked by the Department for Energy Security and Net Zero (DESNZ) to assess evidence on the risks from storage, distribution, and use of 100% hydrogen for heating.

The gas network industry and DESNZ have been responsible for the production and presentation of the evidence base to HSE. This report provides HSE's independent assessment of that evidence.

The legislative framework for workplace health and safety

The Health and Safety at Work etc Act 1974 is the primary piece of legislation covering occupational health and safety in Great Britain. It is a principles-based act that sets out the general duties which employers have towards employees and members of the public.

At the heart of this framework and the British health and safety system is the concept of reducing risk 'so far as is reasonably practicable'. Determining what is reasonably practicable involves weighing the risk against the effort, time and money needed to control it. The greater the risk being imposed on people, the greater the effort required to reduce the risks so that they can be considered to be As Low as Reasonably Practicable (ALARP). This principle applies to the current gas system and will be applied to any potential use of hydrogen for heating.

For the purposes of this assessment, HSE has considered the extent to which the gas network industry has demonstrated whether there is a basis for a credible ALARP demonstration in the event of a potential roll out of hydrogen heating.

As hydrogen for heating is an emerging technology HSE anticipates that safety management will evolve to reflect technical capability at a given time in regard to inputs such as materials, processes, and competence. This will be based on relevant consolidated findings of developing science, technology, and experience, meaning that the inputs for an ALARP demonstration may change over time.

The gas network industry has sought to demonstrate through their evidence submissions that the risks from hydrogen can be managed to a level that is as safe or safer than the current natural gas system for heating.

The Future Regulatory Framework

In addition to the review of the safety evidence, HSE has considered what, if any, amendments might be required to the regulatory framework to meet the challenge of any potential roll out at scale of hydrogen heating, including the safe storage, distribution, and subsequent use in domestic, industrial, and commercial premises.

Safety demonstration

Evidence submitted to HSE has included a broad range of factors including network safety and storage, materials and components, risk assessment, standards and procedures, capability, and training; and end use settings including domestic (including public behaviours), complex domestic (such as multi occupancy buildings), and industrial and commercial settings.

This assessment is based on evidence submitted to the programme by 29th November 2024. However, HSE notes that work on the evidence base has continued to evolve, and work has been undertaken by the Gas Network Industry to update some of the submissions HSE reviewed for this report.

The full list of evidence submissions referenced in this document is available in Annex 'A' to the main report.

HSE has reviewed the evidence submitted, which has included consideration of:

- what issue the submission sought to address,
- how far the evidence piece has addressed the issue,
- whether the submission presented any critical issues, and
- any remaining evidence gaps.

The review has only considered issues relating to the management of health and safety.

Trials data for this assessment

This assessment does not apply to the H100 Fife Neighbourhood trial. HSE is separately assessing the site-specific evidence provided by SGN for H100 Fife and will write to SGN, DESNZ and OFGEM with the conclusions of that assessment.

The timing of the two trials H100 Fife and LTS Futures, which are scheduled to 'go live' in mid to late 2025 means that no operational evidence from those trials has been considered in the broader evidence assessment.

While demonstration properties have been operated, their purpose is to provide members of the public with examples of how 100% hydrogen domestic settings look and feel. These are managed on a site-by-site basis and have not been used by the gas network industry to support the evidence demonstration for a broader roll out of hydrogen heating.

Conclusions

Underground Hydrogen Storage (UHS)

The development of UHS has been considered as part of the infrastructure required for 100% hydrogen heating.

HSE considers that the development of underground hydrogen fast cyclical storage in the UK, within repurposed or new solution-mined salt caverns, is potentially feasible. A partial safety demonstration has been made, however further increases in technological readiness and associated safety considerations would be required to demonstrate that the risks can be managed in line with regulatory requirements.

For other types of storage, including lined rock caverns, depleted gas fields or saline aquifers, significant further technological development and evidence of safety consideration would be required to support hydrogen storage in the UK.

National Transmission System (NTS)

It is potentially feasible to convert the use of the NTS from the transportation of natural gas to hydrogen. However, there are a range of outstanding issues that the gas network industry would need to address. These include:

- Continued review of asset identification and assessment of asset construction, condition and operation,
- The assessment and management of revised hazardous areas
- Pipeline intervention activities, including decommissioning and recommissioning.

However, while the evidence demonstration supports near term potential use of the NTS, the longer-term impacts from hydrogen service remain to be determined. The level of assurance that can be gained from experimental data when considering potential long-term real-world exposure is limited. Operational learning, supported by further research will be key to validating the evidence base provided. It is likely that current integrity management approaches should support this validation if adapted to hydrogen service.

HSE notes that the use of line-pack (for storage) of hydrogen within the NTS will likely be compromised due to potential restrictions placed upon maximum allowable

working pressure and fatigue life of pipeline assets. The implications for the resilience of hydrogen gas supply would need to be considered.

Local Transmission System (LTS)

It is potentially feasible to convert the use of the LTS from the transportation of natural gas to hydrogen.

However, while the evidence demonstration supports near term potential use of the LTS, similarly to the NTS the longer-term impacts from hydrogen service remain to be determined.

There remain a range of outstanding issues that the gas network industry would need to address. These include gaps in knowledge relating to the suitability and condition of critical equipment such as pressure reduction installations that are integral to the pipeline network.

Local Distribution System (LDS)

It is potentially feasible to convert the use of the LDS from the transportation of natural gas to hydrogen.

However, while elements of the LDS will be subject to an inspection and maintenance regime, the buried and legacy pipework in the LDS presents a challenge to inspection. Reference has been made to enhanced leakage surveillance, but specific solutions have not been provided.

HSE considers that it is feasible that legacy iron pipes of suitable specification and condition can be operated in hydrogen service up to 2 barg, based upon the original design pressure of the pipework. However, there has been insufficient evidence provided so far relating to what inspection and surveillance techniques will be deployed and maintenance regime implemented over and above the current approach to enable HSE to comment on its suitability.

HSE considers that the approach to the identification of unknown assets appears reasonable. However, this remains dependent on the development of detailed scopes and the quality of the outputs. Where asset identification can't be specifically assured, the means for addressing this has yet to be determined and as such this represents an evidence gap at this stage.

The level of assurance that can be gained from experimental data when considering potential long-term real-world exposure is limited. Similarly, to the NTS and LTS, operational learning, supported by further research, will be key to validating the longer-term impacts from hydrogen service.

Domestic

Overall, HSE considers that it is potentially feasible to convert the domestic natural gas system for use with 100% hydrogen for heating.

HSE considers that evidence on the compatibility of typical materials used downstream of the ECV within domestic and small commercial premises shows that most conventional materials are acceptable for use in hydrogen service. However, there will be some non-conforming or unsuitable materials in some properties that would need to be replaced prior to any conversion. Removal of these non-conforming materials requires effective identification. HSE considers that additional means of confirming the suitability of materials shall be required beyond that of visual inspection proposed by the gas distribution industry.

Research into the phenomenon of air ingress, a mechanism by which air can enter the pipework system and create a flammable mix within the pipework is a developing area and mitigations are yet to be demonstrated for deployment at national scale.

However, HSE considers that the mitigations presented to date for domestic settings appear appropriate but must in due course take into consideration the issue of air ingress. The universal deployment of domestic hydrogen detectors presents a positive safety mitigation, however, robust consideration of reliability issues, ability for hydrogen detectors to detect all leaks, for example, leaks under floorboards, protection of vulnerable users and user behaviour.

Multi Occupancy Buildings (MOBs)

It may be feasible to repurpose existing gas network infrastructure associated with MOBs. However, a full demonstration of how the risks could be managed in line with regulatory requirements has not been made at this time.

The evidence indicates significant system replacement or remediation would be required prior to repurposing. Conformity with industry standards would be expected in order to satisfy regulatory requirements.

The research on the phenomenon of air ingress is limited to simple, domestic settings. This represents a significant evidence gap for MOBs.

Asset condition and suitability assessment represents a challenge. A methodology underpinning inspection and assessment would need to be developed.

Effective collaborative work between the gas and housing industries would be required to ensure compliance with both building and gas safety legislation.

Industrial and commercial

Only limited evidence has been presented on industrial and commercial settings. This evidence cannot be extrapolated by HSE to draw general conclusions across the diverse range of industrial and commercial settings at a national level. Any future roll out would require site-specific risk assessment, drawing on relevant standards and guidance. HSE also notes that the research on the phenomenon of air ingress is limited to simple, domestic settings. This represents a significant evidence gap for industrial and commercial settings.

This conclusion only applies to the repurposing of natural gas to hydrogen for heating within existing industrial or commercial premises. This assessment has not considered current or future wider industrial applications of hydrogen beyond hydrogen for heating.

Summary

Overall, HSE considers that it is potentially feasible to convert the natural gas system for use with 100% hydrogen heating. The work submitted to HSE constitutes a developing evidence base that is building towards a demonstration of how the risks could be managed in line with regulatory requirements in the event of a roll out at scale. No fundamental safety barriers have been identified by HSE's assessment; however, a full evidence demonstration has not been made at this time.

HSE notes the overall reliance on the principle of site-specific risk assessment using location specific data and conditions to determine such things as the replacement of unsuitable materials in a wide range of network settings, the choice of mitigations in end use and other settings etc. Whilst this more effectively tailors risk evaluation and is a fundamental premise for the management of safety in the UK, this could lead to a degree of variability in its application during a roll out of hydrogen at a national scale simply due to the extent of the decision-making being undertaken. The gas distribution industry would need to ensure that the consistency of decision making is carefully planned and managed at scale. HSE expects that, initially, a degree of conservatism would be incorporated into any risk-based decision making to account for the uncertainty associated with the use of a novel technology.

There are a broad range of issues that Government and the gas network industry would need to consider in advance of any national roll out. Currently, particular evidence limitations and constraints relate to:

- The reliance on the principle of site-specific risk assessment means that it is not possible to determine the extent of remediation or replacement required to repurpose the current gas network.
- The lack of operational data represents a constraint. Operational learning, supported by further research will be key to validating the evidence base provided.

- While the evidence demonstration supports near term potential use of hydrogen the longer-term impacts from hydrogen service remain to be determined.
- Material performance would need to be monitored to identify any emerging long-term suitability issues. If materials were shown to be unsuitable or if there is any doubt over their suitability, further action would be required.
- The modelling on ignition consequences indicates that in the event of an incident involving 100% hydrogen, greater impacts to people and property could result.
- Some industry standards have been developed to support the use of 100% hydrogen. Further work is underway to develop, update and agree relevant standards. This will support the development of Relevant Good Practice over time.

As hydrogen for heating is an emerging technology, HSE anticipates that safety management will evolve to reflect technical capability at a given time in regard to inputs such as materials, processes, and competence. This will be based on relevant consolidated findings of developing science, technology, and experience, meaning that the inputs for demonstration of regulatory compliance may change over time.

The safety considerations outlined could result in cost and feasibility implications that would need to be determined.

HSE considers that a direct like for like comparison between 100% hydrogen and natural gas is inherently challenging and comes with limitations.

The evidence indicates that it may be possible to manage the average levels of risk associated with the operation of a hydrogen network to the level of the natural gas system. However, HSE notes that the risk modelling is sensitive to the inputs provided. Changes to these inputs could lead to different results.

Section 2. Background

Context

In 2019, the UK became the first major economy to pass laws to reduce its greenhouse gas emissions to net zero by 2050. Meeting the net zero target will require virtually all heat in buildings to be decarbonised. The government already supports existing low carbon heat options like heat pumps and heat networks, which will be the primary means of decarbonisation for the foreseeable future. Unlike other decarbonisation options, 100% hydrogen for heating is not yet an established technology. A programme of research, development and testing has been underway for several years on the feasibility, costs, and convenience of hydrogen for heating and a significant body of evidence now exists.

HSE's role

Health and Safety Executive (HSE) is Great Britain's independent national regulator for workplace health and safety. HSE's mission is to protect people and places. HSE's remit includes regulating to protect people against ill health, injury or death from work activities in Great Britain.

In line with its 10-year strategy¹, HSE is working to enable industries to innovate safely to prevent major incidents, supporting the move towards net zero, recognising that many of these technologies present challenges that businesses and society are less familiar with.

As part of supporting the UK government's net zero targets, HSE has been asked by the Department for Energy Security and Net Zero (DESNZ) to assess evidence on the risks from storage, distribution, and use of 100% hydrogen for heating.

The gas network industry and DESNZ have been responsible for the production and presentation of the evidence base to HSE. This report provides HSE's independent assessment of that evidence.

The legislative framework for workplace health and safety

The Health and Safety at Work etc Act 1974 is the primary piece of legislation covering occupational health and safety in Great Britain. It is sometimes referred to as HSWA, the HSW Act, the 1974 Act or HASAWA. It is a principles-based act that

¹ HSE 10 Year Strategy, HSE, 2022

sets out the general duties which employers have towards employees and members of the public.

Employers (duty holders) are required by law to protect employees, and others, from harm that could arise from their work activities.

For the storage and distribution of natural gas there is a mature regulatory framework, including the Gas Safety (Management) Regulations 1996 (GSMR) and the Control of Major Accident Hazards (COMAH) Regulations 2015. While the requirements of GSMR do not apply to 100% hydrogen, the general duties set out in HSWA provide a framework under which the gas network industry have sought to demonstrate how regulatory compliance would be achieved for the use of 100% hydrogen for heating.

At the heart of this framework and the British health and safety system is the concept of reducing risk 'so far as is reasonably practicable'. Determining what is reasonably practicable involves weighing the risk against the effort, time and money needed to control it. The greater the risk being imposed on people, the greater the effort required to reduce the risks so that they can be considered to be As Low as Reasonably Practicable (ALARP). This principle applies to the current gas system and will be applied to any potential use of hydrogen for heating.

Elements of any demonstration on how health and safety will be managed can include a combination of qualitative and quantitative assessment and scientific analysis. Qualitative assessment can be informed by reference to such things as current 'Relevant Good Practice' (RGP), professional judgement and lessons learned from previous experience.

Quantitative analysis can be undertaken to estimate the potential levels of risk associated with an activity and can be used to support consideration of the tolerability of risk. In this context, 'tolerable' does not mean 'acceptable'. This refers to a willingness by society as a whole to live with a risk so as to secure certain benefits in the confidence that the risk is one that is worth taking and that it is being properly controlled. However, it does not imply that the risk will be acceptable to everyone, i.e. that everyone would agree without reservation to take the risk or have it imposed on them.

For the purposes of this assessment, HSE has considered the extent to which the gas network industry has demonstrated whether there is a basis for a credible ALARP demonstration in the event of a potential roll out of hydrogen heating. It does not confirm that an ALARP demonstration has been made as, in any future roll out, the gas network industry's approach to the management of health and safety would need to be specific to the circumstances of the proposed roll out area and end uses. The conclusions will consider the degree to which the evidence could support a demonstration of how regulatory requirements could be met. Risks should continue

to be reviewed as more knowledge and understanding of the use of hydrogen is developed and it may be reasonable to apply additional risk reduction measures to control and/or mitigate risks further.

As hydrogen for heating is an emerging technology HSE anticipates that safety management will evolve to reflect technical capability at a given time in regard to inputs such as materials, processes, and competence. This will be based on relevant consolidated findings of developing science, technology, and experience, meaning that the inputs for an ALARP demonstration may change over time.

Comparative assessment

The gas network industry has sought to demonstrate through their evidence submissions that the risks from hydrogen can be managed to a level that is as safe or safer than the current natural gas system for heating. While HSE considers that any like-for-like comparison between hydrogen and natural gas is challenging, the role of this risk assessment and comparative assessment to natural gas is considered in this report.

The Future Regulatory Framework

In addition to the review of the safety evidence, HSE has considered what, if any, amendments might be required to the regulatory framework to meet the challenge of any potential roll out at scale of hydrogen heating, including the safe storage, distribution, and subsequent use in domestic, industrial, and commercial premises. HSE outlined its initial views on potential regulatory changes via a Call for Evidence² that ran between 15 September 2023 to 27 October 2023. This Call for Evidence specifically tested potential amendments to Gas Safety (Management) Regulations 1996 (GSMR) and the Gas Safety (Installation and Use) Regulations 1998 (GSIUR).

HSE does not intend to start the process of proposing amendments to regulations prior to any Government policy decision on 100% hydrogen for heating. Any legislative change would entail further evidence gathering, public consultation and the development of relevant impact assessment(s).

This report does not detail the nature of any potential changes, however, it does provide commentary on specific elements of the regulatory framework where appropriate.

² Call For Evidence on 100% Hydrogen Heating – Future Regulation, HSE, 2023

Section 3. Overview of Evidence

Safety demonstration

Evidence submitted to HSE has included a broad range of factors including network safety and storage, materials and components, risk assessment, standards and procedures, capability, and training; and end use settings including domestic (including public behaviours), complex domestic (such as multi occupancy buildings), and industrial and commercial settings.

Prior to the evidence review programme, HSE considered the areas of safety demonstration that would be likely to support a policy decision. HSE did not direct the evidence that the gas network industry and DESNZ submitted for HSE's review, and the factors HSE noted for review should not be considered a definitive or exhaustive list of potential safety considerations.

This assessment is based on evidence submitted to the programme by 29th November 2024. However, HSE notes that work on the evidence base has continued to evolve, and work has been undertaken by the Gas Network Industry to update some of the submissions HSE reviewed for this report.

The full list of evidence submissions referenced in this document is available in Annex 'A'.

HSE has reviewed the evidence submitted, which has included consideration of:

- what issue the submission sought to address,
- how far the evidence piece has addressed the issue,
- whether the submission presented any critical issues, and
- any remaining evidence gaps.

The review has only considered issues relating to the management of health and safety.

This report is structured to address the safety evidence presented for each part of the gas network from storage, through the transmission and distribution systems to end use settings. It then addresses the evidence presented for the overarching consideration of risk assessment, proposed mitigations and a National Hydrogen Safety Assessment which sets out at a high level how conversion would be undertaken.

The role of trials

Hy4Heat

In 2018, the then Department for Business, Energy & Industrial Strategy established the Hy4Heat programme to consider if it was technically possible, safe, and convenient to replace natural gas (methane) with hydrogen in residential and commercial buildings and gas appliances. This provided an initial evidence base to help the Government determine whether to proceed towards community trials.

HSE assessed the evidence generated by Hy4Heat and concluded that it provided an adequate basis:

- for designing the scope of future hydrogen trials.
- assessment of the risks arising from those trials, and
- management of those risks in accordance with a suitable and sufficient risk assessment for those trials.

While this programme provided a useful basis for the design of hydrogen trials and further relevant site-specific evidence, significant further evidence was required to demonstrate the safe distribution, storage, and use of 100% hydrogen heating in the context of a national roll out.

H100 Fife – Neighbourhood trial

The timings for SGN's final evidence submission for H100 did not align with this broader evidence review, and this assessment does not apply to H100. HSE is separately assessing the site-specific evidence provided by SGN for H100 and will write to SGN, DESNZ and OFGEM with the conclusions of that assessment.

While trials are helpful to demonstrate that conversion may be possible in site-specific circumstances, due to the limited nature of trials the safety evidence generated for the trials cannot generally be extrapolated to the entire gas network or all property types.

LTS Futures

The LTS Futures project, which repurposes a decommissioned 30km pipeline from Grangemouth to Granton to hydrogen gas, aims to test the compatibility of the Local Transmission System (LTS) to transport hydrogen.

As part of the evidence demonstration for this trial, elements of the supporting evidence package have been submitted to support the broader evidence assessment for a national deployment of hydrogen for heating. However, a number of relevant LTS evidence workstream submissions were not available for HSE to review as part of this assessment.

Trials data for this assessment

The timing of H100 and LTS Futures, which are scheduled to 'go live' in mid to late 2025, means that no operational evidence from those trials has been considered in the broader evidence assessment.

While demonstration properties have been operated, their purpose is to provide members of the public with examples of how 100% hydrogen domestic settings look and feel. These are managed on a site-by-site basis and have not been used by the gas network industry to support the evidence demonstration for a broader roll out of hydrogen heating.

Section 4. Assessment of Evidence

Introduction to the UK gas system

Great Britain's (GB) gas supply is mainly from the UK Continental Shelf and Norway, via onshore gas terminals augmented by Liquid Natural Gas (LNG) shipments which run to the GB's three main LNG import terminals located at the Isle of Grain, South Hook and Milford Haven.

In addition, there are two pipeline interconnectors between the UK, Belgium and the Netherlands. Typically, the GB exports gas via these pipelines during the summer and imports it during the winter.

From the gas importation terminals, gas is transported via a network of high-pressure steel pipelines known as the National Transmission System (NTS) where it feeds large industrial users (e.g. power stations), and the Local Transmission System which in turn feed the local Gas Distribution Networks (GDNs). The GDNs transport gas and are owned by four companies - Cadent, Northern Gas Networks, SGN, and Wales & West Utilities. Independent Gas Transporters (IGT) also supply gas via pipeline. The operators of the GDN's and IGT's then transport gas at lower pressures to industrial, commercial, and domestic users.

Both the NTS and LTS are used to provide strategic gas storage to meet fluctuations in the demand profile of GB gas storage.

Gas is also stored in high pressure gas storage facilities, depleted oil and gas reservoirs and salt caverns. These are used as means of providing additional short-term supplies should extra gas be required to meet spikes in demand.

Section 5. Hydrogen production

Introduction

Production of hydrogen is not within scope of HSE's evidence review and no evidence has been provided by the gas networks or DESNZ.

The regulatory framework for hydrogen production (and associated storage)

Hydrogen production (and associated storage) is subject to existing health and safety legislation. Under the provisions of the HSWA, all employers in Great Britain are legally required to protect their employees, and third parties including members of the public who may be affected by their work activities.

The COMAH Regulations aim to prevent major accidents and, should one happen, limit the effects on people and the environment. With regards to its application to hydrogen, the general requirements of COMAH apply to operators who store at or above 5 tonnes of hydrogen. These businesses must consider the potential for a major accident arising from their work activities and describe their approach to controlling the risks in a Major Accident Prevention Policy.

Additional requirements apply where operators increase their inventories of dangerous substances above the relevant Upper Tier threshold (at or above 50 tonnes for hydrogen). Upper Tier COMAH operators must submit a Safety Report to HSE and the relevant environmental agency – acting together as the COMAH Competent Authority - outlining how they will manage risks arising from their activities. Any changes to the risks or to the control measures applied should be carefully considered and appropriate revisions to their systems, and the safety report, for managing and controlling related risks should be made.

The COMAH Regulations do not apply to sites storing below the Lower Tier threshold quantities of dangerous substances (below 5 tonnes of hydrogen), but dutyholders will still have duties under health and safety regulations.

Hazardous Substances Consent (HSC) is required for all sites which propose to store inventories of hydrogen at or above 2 tonnes.

HSC is a planning control that enables a Hazardous Substances Authority (HSA) to consider whether the presence of a significant quantity of a hazardous substance is appropriate having regard to the risk to the community.

HSE is a statutory consultee to the HSC process and undertakes the public safety risk assessment to inform the HSA decision making process. HSE will produce a map with three risk zones, representing defined levels of residual risk or harm to people which a hypothetical individual could be subject to. If the HSA grants consent, this map defines the consultation distance within which HSE must be consulted over any relevant future planning development.

Depending on the nature of a hydrogen roll out and supporting infrastructure (or the development of a broader hydrogen economy), HSE notes that it is possible that a more localised model supported by distributed production and above ground storage could lead to an increase in the number of COMAH operators. HSE would maintain its regulatory oversight of future hydrogen storage, including consideration of any developing evidence that might indicate the potential need for regulatory change.

As an emerging technology, hydrogen production sites will generally be new (compared to the proposed repurposing of the existing gas network) and expected to be designed with appropriate health and safety controls in place (as would be the case with any new industrial facility).

Section 6. Underground Hydrogen Storage

The development of Underground Hydrogen Storage (UHS) has been considered as part of the infrastructure required for 100% hydrogen heating.

HSE considers that the development of underground hydrogen fast cyclical storage in the UK, within repurposed or new solution-mined salt caverns, is potentially feasible. A partial safety demonstration has been made, however further increases in technological readiness and associated safety considerations would be required to demonstrate that the risks can be managed in line with regulatory requirements.

For other types of storage, including lined rock caverns, depleted gas fields or saline aquifers, significant further technological development and evidence of safety consideration would be required to support hydrogen storage in the UK.

Further consideration would be needed for alternative roll out assumptions that considered a role for above ground storage.

Introduction to Underground Hydrogen Storage

The development of Underground Hydrogen Storage (UHS) has been considered as part of the infrastructure required for 100% hydrogen heating. Depending on the architecture of any future hydrogen system (i.e., based upon the overall demand for hydrogen, location-specific capacity requirements, etc.), various storage options could be considered.

DESNZ identified a range of third-party publications on UHS, which were submitted as evidence for HSE review, including publications from international sources. The submitted evidence considered the following storage technologies:

- Salt caverns – Artificial cavities created in underground salt formations through the dissolution of rock salt by water injection, in a process known as solution mining.
- Depleted gas fields – The available storage volume results from the prior extraction of hydrocarbons and is defined by the pore space in a (once) gas-bearing rock formation.
- Saline aquifers – The available storage capacity is defined by the porous, water bearing rock formations.

- Lined rock cavern (LRC) storage - Excavated subterranean chambers, sealed with a lining system, i.e., a Lined Natural Rock Cavern (LNRC) or a Lined Mined Rock Cavern (LMRC).

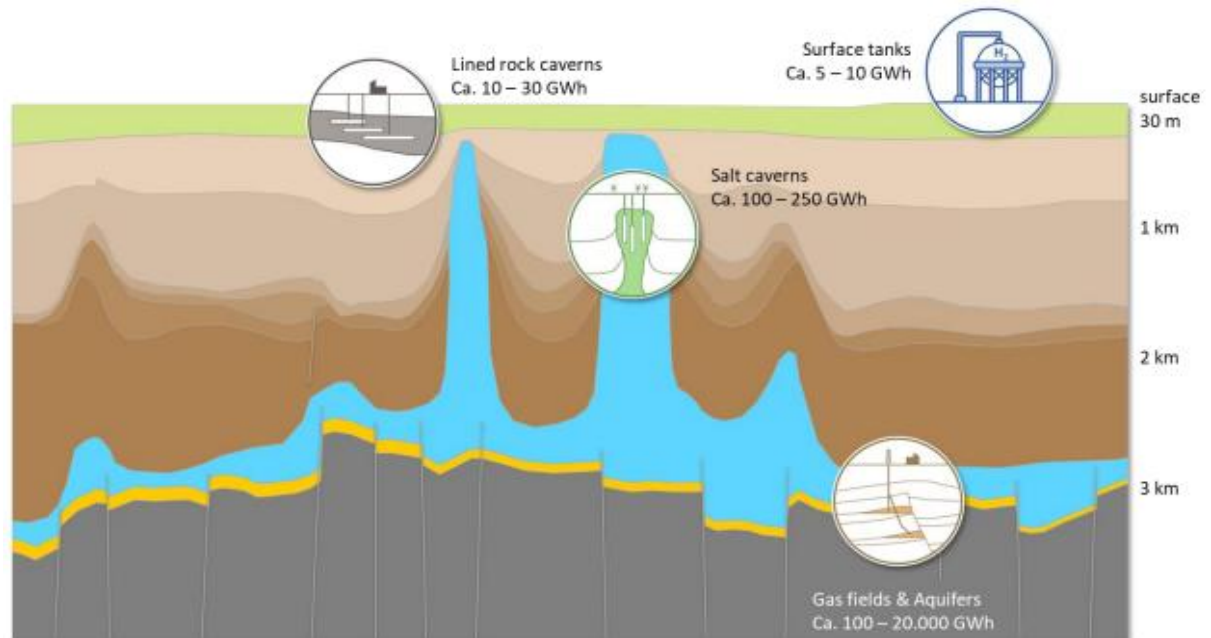


Figure 1 - Diagram showing below ground cutaway of caverns and gas fields³

On the advice of DESNZ, HSE has assumed that hydrogen heating would be predominantly reliant on large scale geological storage.

HSE did not receive or review evidence for above ground storage or consider the potential impacts on system operation for a more localised and distributed storage and supply model. Further consideration would be needed for alternative roll out assumptions that considered a role for above ground storage.

Established above ground technologies (e.g. pressure vessels or gas cylinders / tube trailers) have limited capacity but could potentially be employed for localised, small-scale, energy storage where relevant safety regulatory requirements have been considered.

HSE notes the future potential and benefits of white hydrogen (naturally occurring hydrogen), but HSE did not receive or review evidence on potential hydrogen-bearing rocks in the UK (e.g. in the West of Shetland Basin), or on associated hydrogen storage and distribution solutions.

³ Hydrogen TCP-Task 42, Underground Hydrogen Storage, Technology Monitor Report, 2023

UK-based (storage) evidence

In the UK, salt caverns are predominantly employed for the storage of hydrocarbons including natural gas (methane), liquified petroleum gas (LPG), and crude oil. A potential risk associated with repurposing hydrocarbon caverns for hydrogen duty is the entrainment of contaminants within the gas stream, and subsequent downstream corrosion effects. However, no UK-based evidence was submitted on repurposing caverns previously used for hydrocarbon storage.

Hydrogen is currently stored within three salt caverns, located in Saltholme Brinefield, Teesside, which have been operational since the 1970s. The Teesside salt caverns operate at pressures of 45 to 50 bar and are relatively small, storing around 210,000 cubic metres (m³) of hydrogen in total, for use in industrial processes. The caverns have a combined estimated energy storage potential of 25 gigawatt-hours (GWh). These three caverns do not provide sufficient capacity to meet the likely demand for hydrogen storage in the UK.

DESNZ submitted two UK-based evidence packages for review, relating to the development of additional UHS in salt caverns. These consisted of:

- A salt cavern re-purposing study considering conversion from nitrogen to hydrogen storage.
- An assessment of geological suitability, preliminary design, and safety of gas in salt caverns.

International storage research

To supplement the UK-based evidence currently available on large-scale hydrogen storage, DESNZ requested that HSE review published reports from the following international research initiatives:

- International Energy Agency (IEA) Technology Collaboration Programme, Task 42 - Technology Monitor Report on Underground Hydrogen Storage (UHS).
- HYdrogen STORAge In European Subsurface (HYSTORIES) Project - Work Packages 3 (Microbiology) and 4 (Materials and Corrosion)
- Hydrogen Underground Storage in Porous Reservoirs (HyUSPre) Project - Work Packages 2 (Geochemistry), 3 (Microbiology) and 5 (Integrity & Durability).

HSE's evidence assessment

Significant findings from HSE's review of the evidence submissions are summarised below.

HSE expects further UK-based evidence is likely to emerge in the near future, as more project proposals develop, Final Investment Decisions are reached and projects progress.

With regards to evidence from international research projects, the IEA report collated information and research data relating to various storage technologies including salt caverns, depleted gas fields, aquifers, and lined rock caverns. The main findings, and the evidence gaps identified (often applicable across multiple storage technologies), were summarised under the following themes:

- Geochemical and microbial processes
- Storage facilities and wells
- Storage integrity
- Storage performance

Similar themes were addressed within the Hystories⁴ and HyUSPRe⁵ research project publications.

Geochemical and microbial processes

The evidence submissions indicated that hydrogen is likely to undergo or trigger geochemical and microbial reactions in subsurface reservoirs. Due to their more complex and diverse mineralogical and fluid composition, depleted gas fields and aquifers (collectively termed porous rock formations) are more likely to be affected by such processes than salt caverns.

Potential hazards and adverse effects related to geochemical and microbial processes were identified and evaluated. Of significance was the potential production of hydrogen sulphide (H₂S), predominantly in porous rock formations exposed to hydrogen. In the presence of moisture, H₂S forms sulphurous and sulphuric acids, which are corrosive to metals. This corrosivity is enhanced in the presence of carbon dioxide (CO₂) and is likely to have a detrimental effect on connecting pipelines and surface equipment, potentially increasing the risk of loss of containment.

Experiments demonstrated that H₂S could be produced by processes such as hydrogen-induced pyrite reduction (commencing at 80 - 90°C, with extensive and

4 Hydrogen Storage in European Sub-Surface, European Union, 2023

5 Hydrogen Underground Storage in Porous Reservoirs, European Union, 2024

rapid reactions above 120°C) and hydrogen induced redox reactions. Studies indicated that the latter are mainly catalysed microbially (via hydrogen-utilising microorganisms).

Under the right conditions, hydrogen may be consumed (metabolically converted) to produce contaminants such as H₂S and methane (CH₄). This phenomenon was reportedly observed in a town gas storage facility in the Czech Republic.

A decrease in hydrogen concentration of up to 44% (due to metabolic conversion) was observed experimentally. Preliminary results from further experiments confirmed the production of H₂S, CH₄, and acetate from the conversion process, at temperatures ranging from 35 to 80 °C.

The essential parameters that influence the microbial activity of hydrogen-utilising microorganisms in underground hydrogen storage were defined and a simplified chart was presented within Hystories WP3⁶, illustrating a preliminary risk assessment approach for UHS which was based upon temperature, salinity, carbon, and sulphate availability.

HSE considers that this simplified chart for assessing microbial risks could represent a useful tool for initial, high-level, screening of porous reservoirs (and salt caverns) proposed for hydrogen storage, prior to more comprehensive site-specific evaluation and testing.

The observed criticality of pH level to metabolic conversion (i.e., to both substrate utilisation rate and the inhibition of sulphate reduction reactions) appears significant, with regards to in-service integrity monitoring of reservoirs and the potential mitigation of microbial risks (by pH adjustment).

Further potential options for mitigating microbial risks were detailed and included:

- The use of biocides and other biologically active substances (tests on three EU registered biocides and an in-house biocidal substance were outlined and the advantages and disadvantages of biocide use clearly described).
- Influencing the chemical composition of the formation water (e.g., by water flooding)

HSE considers that significant work would be required to demonstrate the effectiveness of these unproven mitigation measures.

A further adverse effect observed experimentally was anhydrite and calcite dissolution under hydrogen storage. A series of static batch experiments on core (silt and sandstone) samples found that, in several cases, pore-filling anhydrite and carbonate cements within the samples dissolved after six weeks of exposure to

6 Hydrogen Storage in European Sub-Surface (Work Package 3) (report D3.4, Figure 6), 2023

hydrogen. The evidence submission noted that this contradicted current geochemical understanding⁷.

The above experiments were designed to replicate reservoir conditions. Therefore, the extensive changes noted in porosity and permeability (due to dissolving of the cements) are of some concern. If proven to occur at large-scale, such changes could threaten the integrity of porous underground hydrogen storage systems.

It is acknowledged that each of the reactions described were observed under (optimised) laboratory conditions and may therefore represent worst-case scenarios. As such, HSE concurs with the conclusion presented, namely that the current experimental knowledge on geochemical and microbial reactions should be expanded by in-situ and field-scale observations (from pilot and demonstration projects) in multiple geological environments and operational conditions.

The results from hydrogen consumption laboratory tests were employed within zero and three-dimensional models. Caveats to the applicability of the 3D storage scale simulation model (and adjustments / assumptions made to simplify it), were clearly outlined, and HSE concurs that further validation would be required before extending this modelling approach to field cases.

Storage facilities and wells

Evidence indicated the materials and component designs used in storage facilities and wells required detailed review, testing, and confirmation of suitability (or potential modification) prior to their application in hydrogen duty.

The three well materials of major concern for hydrogen duty were identified as metals, elastomers, and cements, with 'key concerns' for each material detailed in the evidence provided.

The strong detrimental impact of hydrogen, on the mechanical properties of steel, was recognised within the evidence packages. Hydrogen embrittlement can manifest in a decrease in ductility and fracture toughness and can increase the susceptibility of steel to fatigue cracking.

Recent developments on assessing the suitability of steels for underground storage in hydrogen service were described. For example, a series of tests was carried out to quantify the fracture toughness resistance of a selection of steel grades for Oil Country Tubular Goods (OCTG) pipes, in the presence of pure hydrogen gas. The grades of carbon steel tested included:

- Grade K55 (55 ksi yield strength) for seamless OCTG pipes.
- Grade VM55W (55 ksi yield strength) for weldable OCTG pipes.

7 Hydrogen Underground Storage in Porous Reservoirs (report D2.1), European Union, 2022

- Grade VM80S (L80 / 80 ksi yield strength) for seamless OCTG pipes.

Based upon referenced test results (not provided to HSE as part of the evidence demonstration), the material grades above were said to be suitable for hydrogen service below 100 bar hydrogen pressure, and potentially suitable for higher pressures (but verification of the latter would be required). Fracture testing of further steel grades was planned, along with testing of fatigue crack growth rate on hydrogen exposure.

A further research project assessed the suitability of steels using different methodologies (e.g. constant load tensile testing) in a more demanding corrosive environment in porous media. Test gases included hydrogen and carbon dioxide / hydrogen sulphide at specified pressures, to replicate reservoir conditions.

The project⁸ concluded that the following steels could be used, without any identified restrictions, for hydrogen service:

Table 1 – Steels identified as suitable for hydrogen service

Material	Grade	Type	Comments
Carbon steel	K55	Seamless	Also known as seamless OCTG pipe
Carbon steel	K55	Welded, pre-corroded	Weldable OCTG pipe
Carbon steel	J55	Welded, pre-corroded	Same chemical composition as K55 but minimum tensile strength is lower
Carbon steel	20MnV5		Lowest strength CS tested
Corrosion resistant alloy	Alloy 625	Nickel-chromium-molybdenum alloy	High strength material
Corrosion resistant alloy	Alloy 316L	Low carbon (<0.03%) stainless steel alloy	Austenitic stainless steel
Corrosion resistant alloy	13% Cr	Alloy containing 13% chromium	Martensitic stainless steel

The following steels were considered “applicable with limits” as, although no cracking occurred during constant load testing, the materials showed localised corrosive attack, especially under hydrogen sulphide environments:

- L80 carbon steel (often used in ‘sour’ natural gas wells)
- L80 pre-corroded carbon steel.
- P110 carbon steel (for general use in deep wells)

Of significance was the finding that the following steels failed during constant load testing and were therefore considered unsuitable for use in hydrogen duty:

- Duplex 2205 stainless steel (a high strength, ferritic and austenitic corrosion resistant alloy).
- Quenched L80 carbon steel

The materials selected for testing appeared to be suitably representative. HSE reviewed the test protocols and findings and determined that suitable evidence was presented to support the material suitability conclusions drawn within the project publications. In addition, the conclusions corroborated those presented elsewhere, on the suitability of Grade K55 carbon steel for use in UHS.

The evidence package stated that *"all materials [tested] correspond to the current state of technology, regarding purity, grain size, composition, mechanical properties and microstructure"*. HSE notes that, if existing pipes within natural gas salt caverns or depleted reservoirs were repurposed for hydrogen duty, this may not be the case.

HSE considers that consultation between research bodies and relevant Standard and Guidance committees (e.g., the International Organization for Standardisation (ISO), American Petroleum Institute (API), International Association of Oil & Gas Producers (IOGP)) would be beneficial to promote the development of harmonised benchmarks on materials selection and suitability for UHS.

With regards to hydrogen storage systems, evidence indicated that elastomers are mainly used as packers in wells, to seal off the annulus between the tubing and casing, with nitrile, hydrogenated nitrile, fluoroelastomers and perfluoroelastomers commonly employed.

The finding that elastomers were susceptible to deterioration by hydrogen sulphide was of significance to service in wells. Evaluation of wellbore elastomer performance under cyclic temperature conditions was said to be lacking, and knowledge from experiments or operational experience in hydrogen duty was scarce. The impact of hydrogen on polymer and elastomer materials within the National Transmission System (NTS) is considered elsewhere in this document.

HyUSPre WP5⁹ presented new experimental data on the effects of hydrogen and cyclic loading on the mechanical properties of well cement at (downhole) pressure, temperature, and stress conditions relevant to porous reservoirs. In this study, changes in mechanical properties (Young's modulus, Poisson's ratio, and ultimate strength) were analysed using unconfined compressive strength (UCS) tests and confined cyclic loading tests on Class G¹⁰ basic well cement samples exposed to hydrogen for up to 2 months.

Though some changes in the mechanical properties of the test samples were noted at laboratory scale, the HyUSPre project found no indication that the integrity of cement in wells used for UHS will be significantly affected by exposure to hydrogen.

Caveats to the conclusion drawn were clearly outlined, namely that it was based upon experiments on one type of cement (class G) and a limited set of conditions. Project recommendations for further work included additional tests (to assess reproducibility) and tests on cement samples that were exposed to H₂ and N₂ for longer durations.

HSE considers that an evidence gap remains over a wider range of cement types, under representative reservoir environments. Further evidence is also required to address the additional 'key concerns for cements' in UHS identified within other, previously referenced, research projects (e.g., potential changes in cement permeability, reduced leak tightness at interfaces, influence on the hardening process of cement in newly drilled wells in hydrogen bearing reservoirs).

In addition to well materials, key concerns for well components were reported in the evidence (IEA Technology Monitor Report on Underground Hydrogen Storage¹¹). These covered components such as wellheads, emergency shutdown valves (e.g., subsurface safety valves (SSSVs), tubing and (production) casing, connections, and packers.

The ratio of gas velocity for hydrogen versus natural gas is considered elsewhere within this document but specific concerns for well operations included the possible necessity for slam testing of SSSVs (to verify their effective operation at high H₂ flow rates) and erosion potential (in tubing and production casing) at the wellhead and 'bottom-hole'.

9 Hydrogen Underground Storage in Porous Reservoirs (work Package 5) (report D5.2), European Union, 2023

10 API Specification 10A, Specification for Cements and Materials for Well Cementing, American Petroleum Institute, 2019

11 Hydrogen TCP-Task 42: Underground Hydrogen Storage - Technology Monitor Report, International Energy Agency, 2023

Storage integrity

Evidence was provided summarising the main processes, concepts and knowledge gaps related to the integrity of UHS. This was based upon operational experience in underground natural gas storage (UGS) and carbon capture and storage, combined with the (limited) available published research on UHS. Based on the knowledge gaps identified, the evidence package recommended additional work activities, as detailed in the four sub-sections below.

Maintaining mechanical integrity of salt caverns under high-frequency loading and unloading with hydrogen

Hydrogen storage caverns are expected to experience regular injection and extraction of hydrogen, resulting in more frequent pressure and temperature cycling than in porous reservoirs. The integrity of hydrogen salt caverns depends on the impact of pressure cycling on creep and damage / permeability development in the cavern walls.

Relevant experience on cyclic loading (from existing UGS, laboratory-scale experiments, and modelling) was summarised. Long-term salt creep behaviour under low-deviatoric stress conditions, away from the cavern wall (i.e., stress which acts to change the cavern shape) was said to be an area of current research, but no details were provided for review, representing an evidence gap. The evidence package indicated that further experience must be gained from salt cavern storage projects, on:

- Permeation and progressive penetration of hydrogen into the damage zone and how this is influenced by compressibility and temperature effects of pure hydrogen, fast-cyclic changes in cavern pressure and potential trapping of hydrogen in the damage zone.
- Influence of cavern design and operations on the rock-mechanical behaviour of a cavern (including pressure build-up) over its entire life cycle.
- Effects of salt creep below brittle overburden rock formation on potential movement along pre-existing faults. Overburden refers to the surface layer of rock that covers the underground storage cavern.

Minimising hydrogen losses via the caprock and seal of porous reservoirs

The evidence submissions asserted that experience from the small number of existing hydrogen storage caverns showed that, although hydrogen is a relatively small and reactive molecule compared to methane, the mechanical integrity of the caverns was not significantly affected by hydrogen.

Laboratory-scale experimental and modelling work was presented and concluded that shale caprock could act as an effective seal for hydrogen, due to its low reactivity with hydrogen. Insignificant hydrogen losses from diffusion and dispersion

were anticipated by the research project team, due to the high capillary entry pressure. However, the potential for leakage through fractured clay-rich rock was said to remain poorly quantified.

The evidence submission recommended the following actions, to improve and confirm the understanding of potential hydrogen losses via the caprock:

- Quantitative experimental work to assess and confirm potential impacts of geochemical reactions on caprock integrity and the effective diffusion and dispersion coefficient of hydrogen in shaley caprock.
- Experimental measurement of breakthrough pressures of hydrogen in shale caprocks under realistic subsurface conditions.
- Monitoring of potential migration of hydrogen through fractures, in laboratory experiments and real subsurface environments.

Though not specifically referencing leakage through fractured clay-rich rock (a risk factor highlighted within the evidence), it is assumed that the latter recommended action includes monitoring hydrogen migration through fractures in such materials.

Predicting fracture network formation and minimising the risk of fault slip during cyclic hydrogen loading and unloading in porous reservoirs

Most knowledge on the impact of cyclic stress, on fracturing and fault slip, comes from UGS projects. The evidence concluded that, for UHS, further quantitative experimental work is needed, on different rock types and under realistic reservoir conditions, to increase understanding of:

- Cyclic loading impacts on reservoir stability and fracture generation and propagation in the presence of hydrogen.
- Effects of mineral precipitation and dissolution and weakening molecular bonds on subcritical crack growth.
- Progressive fatigue of reservoir rock due to intergranular clay swelling / shrinkage cycles.
- Increasing slip-tendency due to geochemical alteration of the fault zone in presence of hydrogen.

HyUSPre¹² investigated the integrity and durability of reservoir rock (and caprock) exposed to hydrogen. Two types of rock sample were evaluated, representative of those found in deep and intermediate porous reservoirs in Europe (at ~ 3300 and 1500 meters deep, respectively).

The laboratory-scale experiments included exposing the rock samples to hydrogen at respective reservoir pressure and temperature conditions to evaluate potential geochemical reactions. Mechanical property and flow tests were completed (to

¹² Hydrogen Underground Storage in Porous Reservoirs (work Package 5), European Union, 2023

assess any effect from hydrogen exposure), followed by pressure cycling (to simulate seasonal demands for injection and withdrawal of hydrogen).

The experimental results were reported as 'complex', with findings differing between the two types of rock tested. The project concluded that the impact of hydrogen exposure and cyclic loading on the mechanical and flow properties of porous reservoir rocks was limited, under the conditions and exposure duration tested in this study. However, the findings emphasised the need for further research and comprehensive assessment to understand the long-term effects of hydrogen exposure and cyclic loading in different geological settings and under extended exposure durations.

Monitoring integrity of caprock, seal, reservoir, and faults

The collated evidence indicated extensive experience in the use of various geophysical and geological measurement and monitoring methods, from existing hydrocarbon extraction and UGS (of natural gas and CO₂). However, experience in the use of these techniques with UHS was said to be lacking and/or the technology immature, with further development required.

HSE agrees with the project recommendation that guidelines, including standards and relevant good practice, should be established to define monitoring objectives and benchmarks for responding to observations in UHS.

Storage performance

Typical operational performance parameters for UHS were defined within the evidence as injection / production rates, accessible working gas volume, required cushion gas volume, recoverability and quality of hydrogen withdrawn from the reservoir, and reservoir / load duration.

These parameters were presented as depending on the interaction between site-specific geological reservoir characteristics and the design / engineering principles applied to the underground storage system and surface facility components (compressors, etc...), with salt caverns and porous reservoirs having very different characteristics.

The evidence presented included a comprehensive illustration summarising the range of (interacting) considerations, risks, and processes, relevant to understanding hydrogen storage performance in solution-mined caverns and porous reservoirs- see Figure 2:

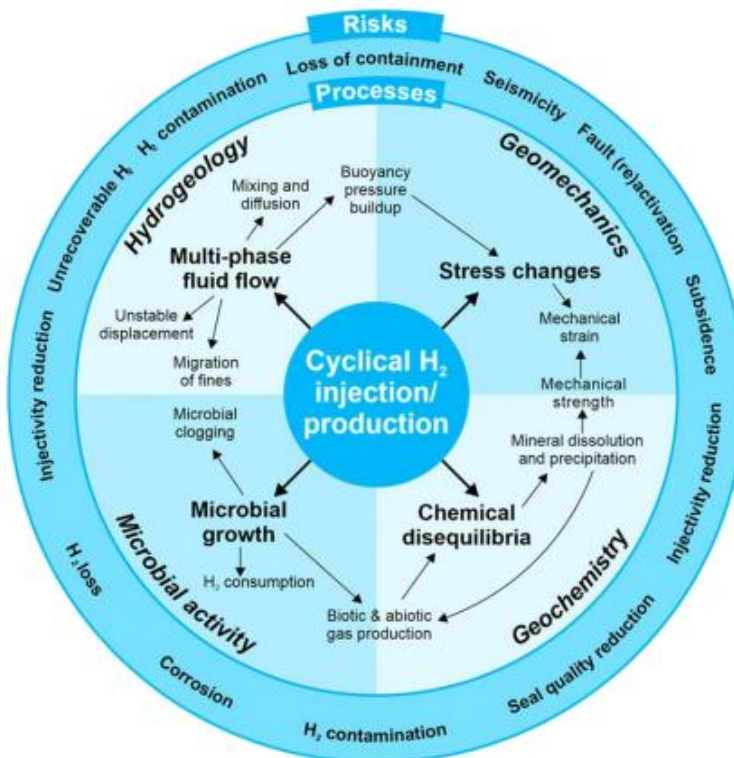


Figure 2 – Diagram showing cyclical hydrogen injection production showing relationships between considerations, risks, and processes, explained further in text.

The need for further improvement of multi-scale models for UHS in porous reservoirs was re-emphasised within the evidence package.

HSE agrees with the statement that sensitivity analyses for quantification of the most influential parameters on reservoir performance (considering field-scale heterogeneities and uncertainties) is likely to be crucial in developing effective and reliable modelling.

HSE considers that the development of site screening procedures (i.e., standardised geo-mechanical and thermodynamic assessment) would support establishing reservoir (and salt cavern) characteristics.

The regulatory framework for hydrogen storage

There is an existing legislative framework in place for hydrogen storage as discussed in the preceding chapter on hydrogen production.

In addition to the legislation cited, the Dangerous Substances and Explosive Atmospheres Regulations 2002 (DSEAR) require the elimination or reduction of risk of fire and explosion from substances connected with work activities. A key part of compliance with DSEAR is the risk assessment and an important principle is to separate storage areas from process areas where the two occur on the same or shared premises.

Conclusions

Evidence was provided demonstrating significant progress in identifying relevant risk factors in relation to UHS in salt caverns, depleted natural gas reservoirs and aquifers, and in investigating and evaluating such issues.

The evidence submissions indicate that hydrogen is likely to undergo or trigger geochemical and microbial reactions in subsurface reservoirs, including the production of hydrogen sulphide (H₂S), often catalysed microbially. HSE considers this finding to be significant, as acid production is likely to have a detrimental effect on connecting pipelines and surface equipment, potentially increasing the risk of loss of containment. However, further work is required before experimental findings can be reliably extrapolated to full-scale UHS. Potential measures for mitigating microbial risks in subsurface reservoirs were identified. However, HSE considers that further work would be required to demonstrate the effectiveness of these unproven mitigation measures.

A geochemical reaction involving the dissolution of pore-filling anhydrite and carbonate cements during core sample testing in hydrogen was reported. This led to changes in the porosity and permeability of the core samples. The evidence package indicated uncertainty over whether the dissolution was hydrogen-induced, or due to experimental artefacts. If proven to occur at large-scale, due to hydrogen-induced dissolution of cements, HSE considers that such changes in porosity and permeability could threaten the integrity of UHS systems.

On storage facilities and wells, evidence submissions identified potentially detrimental effects of exposure to hydrogen on metals, elastomers, and cements. Steel grades which were suitable, “applicable with limits”, or unsuitable for hydrogen duty, were identified via comprehensive testing programmes. However, the testing was carried out using materials which “correspond to the current state of technology, regarding purity, grain size, composition, mechanical properties and microstructure”. HSE considers that, repurposed historical steels, with sub-optimum material properties, could potentially exhibit reduced performance under arduous conditions (e.g., where hydrogen sulphide is present).

Limited evidence was presented on elastomer performance in hydrogen duty and/or under cyclic loading. However, reported test results indicated that elastomers were susceptible to deterioration by hydrogen sulphide. HSE considers this finding to be of significance to service in wells, where H₂S may be present due to the impacts referred to above.

Experimental data was presented on the effects of hydrogen and cyclic loading on the mechanical properties of a particular well cement. Based on the (short duration) tests completed, the researchers found no indication that the integrity of cement in wells used for UHS will be significantly affected by exposure to hydrogen. However,

HSE considers that an evidence gap remains regarding the effects of hydrogen exposure and cyclic loading on a wider range of cement types over an extended time period.

On storage integrity, operational experience in underground [natural] gas storage (UGS) and carbon capture and storage, and recent laboratory-scale experiments investigating the integrity of UHS systems, were suitably described. However, the evidence submissions identified significant remaining knowledge gaps related to storage integrity and recommended further substantial work under realistic UHS system conditions, at laboratory and/or pilot scale, in the following topic areas:

- Maintaining mechanical integrity of salt caverns under high-frequency loading and unloading with hydrogen.
- Minimising hydrogen losses via the caprock and seal of porous reservoirs.
- Predicting fracture network formation and minimising the risk of fault slip during cyclic hydrogen loading and unloading in porous reservoirs.
- Monitoring integrity of caprock, seal, reservoir, and faults.

An evidence submission reported on Technological Readiness Levels of various UHS options. Technology Readiness Levels (TRL) are a type of measurement system used to assess the maturity level of a particular technology. Each technology project is evaluated against the parameters for each technology level and is then assigned a TRL rating based on the projects progress.

Underground salt caverns in static or low cyclic hydrogen storage applications (e.g., the existing UK H₂ caverns) are deemed to have the highest Technology Readiness Level (TRL 9: *Commercial operation in relevant environment*).

Underground salt caverns, used with fast cyclical hydrogen storage, (as is anticipated would be required to support a hydrogen heating network) are assigned a TRL of 5 - 6 (*Large prototype – Full prototype at scale*).

For the remaining UHS technologies considered, TRLs were assigned as follows:

- Hydrogen storage in lined rock caverns (TRL 5: *Large prototype*).
- Hydrogen storage in depleted gas fields (TRL 3 - 4: *Concept needs validation – Early prototype*).
- Hydrogen storage in saline aquifers (TRL 2 – 3: *Application formulated - Concept needs validation*).

HSE concurs with the Technology Readiness Levels outlined above but recognises that further international research and pilot scale projects are currently underway (or proposed), which aim to address outstanding knowledge gaps and increase technological readiness.

A list of EU pilot studies provided by DESNZ indicated that several European countries will see the development of first demonstrators (i.e., TRL 8) before 2030, and subsequent commercial projects (TRL 9), for underground storage of hydrogen.

Overall, based on the evidence provided for review of UHS in the UK, HSE considers that the development of underground hydrogen fast cyclical storage in the UK, within repurposed or new solution-mined salt caverns, is potentially feasible. A partial demonstration has been made, however further technological development and evidence of safety consideration would be required to demonstrate that the risks can be managed in line with regulatory requirements.

Significant technological development and evidence of safety consideration would be required to support hydrogen storage in lined rock caverns, depleted gas fields or saline aquifers.

Further consideration would be needed for alternative roll out assumptions that considered a role for above ground storage.

Additional UK-based evidence on UHS in salt caverns is likely to emerge in the future, as project proposals develop, and comprehensive site-specific demonstration becomes available.

HSE considers that knowledge sharing, where available, will be advantageous to the development of additional UHS in the UK.

Section 7. The National Transmission System

It is potentially feasible to convert the use of the NTS from the transportation of natural gas to hydrogen. However, there are a range of outstanding issues that the gas network industry would need to address. These include:

- Continued review of asset identification and assessment of asset construction, condition and operation,
- The assessment and management of revised hazardous areas
- Pipeline intervention activities, including decommissioning and recommissioning.

However, while the evidence demonstration supports near term potential use of the NTS, the longer-term impacts from hydrogen service remain to be determined. The level of assurance that can be gained from experimental data when considering potential long-term real-world exposure is limited. Operational learning, supported by further research will be key to validating the evidence base provided. It is likely that current integrity management approaches should support this validation if adapted to hydrogen service.

HSE notes that the use of line-pack (for storage) of hydrogen within the NTS will likely be compromised due to potential restrictions placed upon maximum allowable working pressure and fatigue life of pipeline assets. The implications for the resilience of hydrogen gas supply would need to be considered.

Introduction to the National Transmission System

The National Transmission System (NTS) is a network of pipelines operating at a pressure up to 94 barg that transports gas from its point of entry to power stations, industrial plants, storage facilities and to the gas distribution networks and feeds into the LTS. The NTS comprises around 5000 miles of pipeline, more than 60 compressors at 21 compressor stations and more than 500 above ground installations. The NTS supplies gas to the Local Transmission System (LTS) which comprises of a further network of pipelines operating between 7 barg and 70 barg.

HSE reviewed evidence that sought to demonstrate that the NTS can be repurposed for use with 100% hydrogen. The gas network industry's evidence in support of repurposing the NTS from natural gas to 100% hydrogen was largely provided within

the FutureGrid trials and LTS Futures projects. These were supported by studies related to the repurposing of compression systems and capacity.

FutureGrid was commissioned by National Gas Transmission and developed and operated by DNV to demonstrate the suitability of the UK high pressure gas transmission system to be converted to 100% hydrogen. A gas flow facility was designed and constructed at the DNV Spadeadam facility incorporating ex-service assets removed from the existing system during decommissioning activities. The installation is broadly representative of the UK gas transmission pipeline system through the entry point (e.g. onshore gas terminal) to the exit point (e.g. local distribution network).

The LTS Futures programme was conceived to carry out research into the compatibility and suitability of Local Transmission System assets for 100% hydrogen service. The program of work included both testing and trials carried out at the DNV Spadeadam facility as well as a planned operational trial of a repurposed pipeline. The scope of the trials carried out at the test facility included metallurgical performance studies as well as the application of operational pipeline interventions, such as isolations, hot tapping etc. The planned live trial (planned for Summer 2025) will see an existing previously mothballed pipeline running from the Grangemouth refinery site to Granton near Edinburgh operated in hydrogen service for a defined period. It is intended that additional live pipework intervention trials will be carried out whilst the pipeline is operational during the live flow trial.

As discussed in the section 3 concerning the role of trials, evidence from the operation of the LTS Futures trial has not been considered as part of HSE's evidence review as the timing of the trial did not align with the evidence assessment period.

HSE's evidence assessment

Asset Identification – Location, Construction, Condition and Operation

Of critical importance to any conversion strategy is the operator's ability to identify network assets and assess the original specification and quality of the initial installation and to confirm current integrity. The HyNTS Pipeline Dataset Discovery Phase¹³ project aimed to develop the high-level data and data management requirements for repurposing. This also considered the current data available across the NTS and LTS to meet these requirements.

13 Hydrogen National Transmission System Pipeline Dataset Discovery Phase, Rosen Group, 2022

This project was followed by the HyNTS Pipeline Dataset Alpha Phase¹⁴. This was presented as aiming to address two primary issues:

1. to define and gather the data necessary to facilitate the repurposing of above 7 bar pipelines within the NTS and LTS; and
2. to further develop the tools and data capture processes to facilitate effective integrity management decision making following repurposing.

Information on material compatibility is required by the operators to allow for a determination of how hydrogen may adversely affect specific parts of the network. These projects were presented as routes to help identify any parts of the system that may need to be replaced or define the remaining life due to degradation by fatigue.

The HyNTS Inspection System was developed under the Dataset Alpha Phase project, intended to function as a 'toolkit' to address possible data gaps prior to the conversion of the network to hydrogen service using a combination of existing and novel technologies. Consideration was given to the capability of the recommended technologies to adequately identify and quantify integrity threats in hydrogen pipelines. The application of a combination of specific in-line inspection (ILI) tools (such as electronic tools that travel through pipelines using ultrasonic or magnetic sensors) were recommended by the project to close the data gaps identified within the pilot pipeline segment.

Evidence on material compatibility of ILI tools was submitted and was based on a literature review. Findings from laboratory testing of ILI components in hydrogen gas environments were disclosed in the evidence submission with commentary provided on requirements for future testing. Tool run simulations were conducted to evaluate the capability of ILI tools to operate in hydrogen pipelines, considering hydrogen gas properties and operational parameters specific to the pilot segment. The effects of specific tool configurations on run performance were evaluated within the HYNTS Pipeline Dataset Alpha Phase Study.

HSE considers that the approach described within the evidence submissions is appropriate to address the scale of the issue of identifying and confirming the condition and characteristics of pipeline assets to facilitate repurposing the NTS (consideration to the LTS is given in more detail in Section 8). The relevant contributing factors were covered in detail within the evidence pieces, such as existing data status, existing database systems for capturing information, existing pipe condition, existing and future inspection capabilities suitable for new threat mechanisms and an overall risk ranking methodology.

There are ILI and supporting inspection solutions for the varying damage mechanisms and defects for determination of condition i.e. within natural gas service

¹⁴ Hydrogen National Transmission System Pipeline Dataset Alpha Phase, Rosen Group, 2023

prior to conversion. It is recognised that potential damage type and critical geometry will differ for hydrogen service, however baseline data of asset condition can be captured.

There is a need for further development and validation of suitable inspection techniques and equipment for operating within a hydrogen environment. This includes evaluating means of identifying critical degradation and flaws relevant to hydrogen as opposed to natural gas operation. HSE understands that work is planned to develop the inspection and validation techniques against known defects. However, this remains outstanding at the time of this assessment.

Knowledge gaps remain in relation to the application and efficacy of suitable ILI technologies, some being dependent upon specific material, critical defect geometry and size as well as potential degradation mitigation measures such as the application of internal coatings. The successful deployment of ILI technologies will require further development in relation to application and material compatibility, but the challenges are not considered insurmountable. It is the case that there are currently some limitations with deployment of ILI within natural gas so it will be critical to ensure that ILI technology is not used beyond that for which it has been validated through development and trial runs with known flaws and damage.

The Performance of NTS Assets in Hydrogen Service

The HYNTS Future Grid Asset Performance Testing trials facility (HYNTS Future Grid Asset Performance Testing in Hydrogen Service report)¹⁵ enabled the performance testing of network assets to be evaluated using natural gas and hydrogen, and hydrogen blends at different flow rates. The trials also included the performance testing of the operation of pipeline assets such as ball valves, flow control valves, regulators, filters as well as different types of flow meter. A gas chromatograph to test for gas quality and composition was also tested during the trials. Venting operations were also carried out, and a vibration survey was undertaken of the test installation.

The trials concluded that testing undertaken on the FutureGrid flow facility successfully demonstrated the capability of existing ex-service natural gas transmission infrastructure to safely transport hydrogen with most of the assets performing broadly as expected, with testing completed across all gas compositions.

There was, however, a noticeable reported increase in leakage from the test facility when switched to operate on 100% hydrogen, including an increase in leakage through existing known leak sites as well as new leaks occurring.

¹⁵ Hydrogen National Transmission System Future Grid Asset Performance Testing in Hydrogen Service report, DNV, 2024

Not all meters tested were suitable for use with hydrogen. Two meters (the orifice plate meter and clamp-on meter) continued to measure volumetric flow in 100% hydrogen, but other meter types tested were isolated as they were not compatible with 100% hydrogen.

HSE considers that flow metering systems will have to be further developed to ensure stability and accuracy over the required flow ranges with systems being sensitive to gas properties and composition. Metering systems are mature and well understood for natural gas use but would need to be further developed for hydrogen use. There was no noticeable difference reported in ball valve operation when tested using natural gas or hydrogen. One 18" ball valve (V5) had a hydraulic leak to the actuator so could not be operated and a positive seal could not be achieved on the 36" ball valve (V6), with the seal leak previously identified during the natural gas trial and was therefore unable to be tested on hydrogen. As this was the only large ball valve within the scope of the trial, this limits the value of the findings.

The ball valve leak detection was based upon audible detection (by ear) which made evaluation of leak rate less accurate, especially with higher levels of ambient noise. Acoustic emission technologies or other means may have to be considered.

Out of a small sample size of recovered ball valves, the percentage of unserviceable valves, or valves with excessive seat leakage, is of concern if indicative of the general compatibility and condition of NTS assets. It is noted that some leakage was discovered following commissioning so was not hydrogen related, but such assets will exhibit greater leakage in hydrogen service.

When considering flow control valves, the opening and closing times for the 8" Sellafield flow control valve was shorter (40% or more) than for the 18" Enron flow control valve. In general, the closing times were shorter than the opening times. Stroke times for the control valves were said to reduce with higher concentrations of hydrogen and it was understood that operational stability was satisfactory. It was noted, again, that one of the control valves could not be tested due to excessive leakage.

Operation of the high-pressure slam-shut valves did not appear to be affected by the introduction of hydrogen. The evidence reported no notable difference in firing times with each operational test resulting in an instantaneous closure. The low-pressure slam-shut valves tested had required a greater overpressure to initiate closure with increasing hydrogen content, but this could have been attributed to slight changes made to the associated regulator setting, so the impact of hydrogen on performance for low pressure slam shut valves remains inconclusive.

There appeared to be no change in operation of the regulator tested due to the introduction of hydrogen but testing of regulator type was restricted due to the pipework configuration.

Both the 1.5 bar relief valves and a 40-mbar relief valve tested exhibited an increase in operating pressure above the set pressure with increasing hydrogen up to 20% hydrogen. The relief valves were not tested at 100% hydrogen. This represents an evidence gap and further verification of suitability would be required.

The testing of the filters was inconclusive with some instability on differential pressure measurement across the filter skid witnessed.

There had been trials that compared actual recorded temperature change with the modelled Joule-Thompson effect that indicated that it was likely that take offs (downstream of pressure reduction installations (PRIs)) will not require pre-heat in 100% hydrogen service. This could indicate the potential for reduced risks from low temperature effects.

Initial excitation of the test facility had been identified and mitigated with further vibration analysis carried out. As this was atypical of a NTS compressor installation due to being a different type and configuration, the output was of limited value in informing wider repurposing challenges.

HSE considers that the flow control valves were seen to operate successfully in hydrogen duty with some changes in characteristics noted. It would be expected that control valves would require review and potential modification, if being converted to hydrogen service, to ensure material operational and process compatibility for the given operating conditions. However, overall HSE notes the evidence was limited due to the number of valves tested, including one that could not be tested due to leakage, and this represents an evidence gap.

The performance of the slam shut valves was accepted as being unaffected although the drift seen to the relief valve set point requires further investigation. A relief valve would be expected to be designed for the specific fluid and operating conditions and operate at an acceptable level of reliability and repeatability.

The filter systems would need to be reviewed for the fluid and operating conditions to ensure filter performance is maintained and ancillary equipment such as differential pressure gauges are matched to the flow conditions.

The evidence has provided good insight into how pipework and other critical assets will perform in hydrogen service, however there are some areas that require further review. HSE notes that the sample size of components tested with the defined trials is relatively small in comparison to the NTS population.

There are concerns over the integrity of repurposed ancillary assets such as isolation valves and pressure reduction stations, where some larger leaks have been identified during initial leak test and then under hydrogen testing, even after a degree of refurbishment.

Asset integrity – Materials

The materials assessment and testing programmes have provided considerable data in respect of determining suitability of typical materials and pipework configurations for operation in hydrogen service. Hydrogen embrittlement concerns the degradation of materials such as some typical pipeline steels. This could result in a reduction in tensile ductility that can reduce fracture resistance (fracture toughness) and increase fatigue crack growth rate, which are of specific concern to pipeline integrity. In essence this can reduce the strength of the material, making it more prone to fracture under load and accelerated cracking under cyclic conditions (i.e. pressure fluctuations).

Research studies submitted on material suitability and performance were based upon recovered pipeline samples that underwent metallurgical and performance testing. In Technical Report 1 Metallurgical Report on SGN pipes¹⁶, sample pipework sections had also been subject to live operations including the attachment of welded and grouted tees, with the pipework assembly then subjected to fatigue testing. Further assemblies were fabricated with manufactured defects and subject to hydrostatic, natural gas and hydrogen burst tests as detailed with the LTS Futures Element 3¹⁷ submission.

A further trial FutureGrid Hydrogen Fatigue Testing Report¹⁸ saw a recovered 36" line-pipe section used to assess the fatigue performance of typical transmission size and grade pipework with the test pipework assembly having been manufactured with a number of predetermined defects. The outputs from this trial (due after this evidence assessment) are likely to be of significance.

The submission, Materials Testing to Enable Hydrogen Injection in High Pressure Pipelines¹⁹ evaluated the fracture toughness and fatigue properties of the actual line-pipe used for the Future-Grid facility with material samples from seam and girth welds being tested in hydrogen. The material test program also included similar fracture toughness and fatigue testing for a wider range of materials used within the NTS. Technical Memo – NTS Materials Testing to Enable Hydrogen Injections into High Pressure Pipelines - MAOP of FutureGrid Test Facility²⁰ describes the further fracture toughness testing in a hydrogen atmosphere, providing data for grades X52, X60 and X65 pipeline material. ASME B31.12 as well as IGEM/TD/1 and IGEM/T/D/13 supplements provide for two approaches to determining maximum allowable operating pressure. The first option is to apply a typical material

16 Technical Report 1 Metallurgical Report on SGN pipes, TWI, 2024

17 LTS FUTURES: ELEMENT 3 OFFLINE TESTING - WP2: Burst Testing, DNV, 2024

18 FutureGrid Build Hydrogen Fatigue Testing Report, DNV, 2024

19 NTS MATERIALS TESTING TO ENABLE HYDROGEN INJECTION IN HIGH PRESSURE PIPELINES Technical Summary Report, DNV, 2024

20 Technical Memo - NTS Materials Testing to Enable Hydrogen Injections into High Pressure Pipelines- MAOP of FutureGrid Test Facility, DNV, 2024

performance factor for the material grade, in the case of IGEM/TD/1 and IGEM/TD/13 derived from the ASME B31.12, to take account of hydrogen effects. A second option to determine MAOP may be applied if suitable material testing has been carried out, including testing in hydrogen, fabrication quality, current condition in relation to defects (adequately recorded) and fracture mechanics calculations applied to demonstrate adequate material toughness in hydrogen service. This option, of applying higher material performance factors, may potentially allow the use of higher operating pressures as demonstrated by the examples cited. Critical defect (flaw) size and ability to screen for such defects as well as ensuring adequate coverage of material testing such as weld material, parent materials and Heat Affected Zone etc. are also critical to such an approach and have been evaluated. The report included temperature sensitivity and fatigue studies with some geometries identified as having restricted fatigue lives requiring additional scrutiny whilst operational. There were some situations where calculated axial stress was the most critical stress within the pipework configuration demonstrating that it is important to understand all stress limitations related to a particular piping geometry, material characteristics and loading.

Further metallurgical studies were reported via the LTS Futures Material Characterisation and Charpy Impact Testing and Transverse Strip Tensile Testing studies²¹. The fracture toughness and fatigue crack growth rate tests had been carried out on a range of different NTS pipe grade materials in hydrogen environments. These tests showed the measured fracture toughness values were significantly higher than the suggested lower bound value derived from Charpy Impact Energy as per the IGEM/TD/1 hydrogen supplement. The fatigue crack growth rate was observed to be dependent on the cyclic loading frequency, with growth rate increasing as the frequency was reduced from 1 Hz to 0.001 Hz. Fatigue crack growth rates were similar for the range of material grades tested with the majority of fatigue crack growth rate data being lower than the upper bound curve recommended in the IGEM/TD/1 hydrogen supplement.

The Inhibition of Hydrogen Embrittlement Effects in Pipeline Steels²² reported on the potential for using low levels of oxygen within hydrogen to mitigate or reduce the impact from hydrogen embrittlement in common pipeline steels used within the NTS. Inhibition of hydrogen embrittlement by the addition of oxygen was investigated in representative pipeline materials by applying fracture toughness and fatigue crack growth rate testing in environments including air, pure hydrogen and hydrogen with low levels of oxygen (between 50 to 1000 ppm). While HSE considers that the initial results were promising, there would be challenges in application, such as control of injection and uniform distribution.

21 LTS Futures Technical Report 2 Charpy Impact Testing and Transverse Strip Tensile Testing studies, TWI, 2024

22 Inhibition of hydrogen embrittlement effects in pipeline steels, Rosen Group, 2024

The literature-based evidence on Impact of Cathodic Protection (CP) on Coatings²³ concluded that there was no conclusive evidence linking hydrogen permeation to coating breakdown from the evidence provided. HSE notes the lack of operational specific data related to the impact of hydrogen on CP performance. No further conclusions have been provided to HSE with the submission making recommendations for further research. The need for further research represents an evidence gap at this stage.

HSE considers that the approach to testing of pipework materials for use in hydrogen service is appropriate and provides high quality data. Further trials would help validate these findings. LTS Futures and FutureGrid trials were considered to be reasonably appropriate although the Grangemouth to Granton pipeline was not a typical network pipeline due to the transportation of refinery tail gas but was of representative typical materials and construction.

The fracture toughness and fatigue crack growth studies concluded that the recovered pipework components used within the FutureGrid test assembly would be suitable for operation with a maximum allowable operating pressure of 70 barg. Applying the most applicable design code covering hydrogen pipeline systems (ASME B31.1224) to the Future Grid pipework, derives a maximum allowable operating pressure (MAOP) to a level below current NTS pressures. The standard also provides for more analytical methods if the line pipe has been tested, and data is available for fracture toughness and fatigue performance in hydrogen. This alternative analytical approach, if applied, would potentially allow a higher MAOP aligned to the NTS pressures. For this analytical approach to be undertaken accurate asset data is required.

HSE noted that the fatigue lives of the pipework sections sampled were predicted at 20 years in some cases. The HyNTS pipelines dataset submission did not expand on the number of cases that this would apply to and would be dependent upon quality of data and specific assessment.

The Pipeline Integrity Engineers Ltd evidence submission 'Requirements for Qualification of Line pipe Material for Hydrogen Service'²⁵ had identified vintage pipeline materials as being those produced before 1970, with a transition to modern materials between 1971 and 1973. These vintage materials were seen to display moderately lower fracture resistance in gaseous hydrogen in comparison with modern steels displaying larger relative reduction in fracture resistance. There was limited specific data describing the ratio of vintage pipework compared to the total network, however indicative data from work previously undertaken identified 9% of

23 Hydrogen Impact on Pipeline Cathodic Protection Performance and External Coating Degradation, Rosen; The University of Warwick, 2023

24 B31.12 - Hydrogen Piping and Pipelines, The American Society of Mechanical Engineers, 2024

25 Requirements for Qualification of Linepipe Material for Hydrogen Service, Pipeline Integrity Engineers Ltd., 2024

NTS pipework as installed in the 1960s, 40% in the 1970s of which a percentage will be prior to 1973, with 26% being unknown.

The evidence submissions reported that NTS pipeline materials were highly sensitive to assumed input parameters. Good-quality data will be essential when assessing specific assets for continued operation or defining maximum operational parameters in hydrogen service. Critical factors will include initial flaw size, welding residual stress and stress concentrations due to weld misalignment.

HSE considers that the NTS and LTS pipeline assets would require individual assessment based upon required data of adequate confidence, quality and detail to enable repurposing. Where such data is not available, further research or study would be required and / or the application of further mitigation or restriction of the allowable service conditions. The HyNTS Pipeline Dataset provides the basis for the development of the required data for pipeline analysis and what actions will be required to close any gaps in such data.

The Inhibition of Hydrogen Embrittlement project²⁶ tested the impact from the addition of low levels of oxygen. The initial results have been encouraging in reducing the impact of hydrogen on pipeline material properties. However, further research is required to validate the findings and appropriate risk management arrangements would be required to manage its use. Suitably robust means of controlling any injection would be required in order to protect against the development of a hazardous composition. Additionally, good design would be required to ensure adequate mixing and dispersion through the network with the development of suitable verification and monitoring in order to justify what would be a major asset integrity management regime.

Inhibition of hydrogen embrittlement by the application of impermeable coatings, particularly at weld locations, had also been evidenced with some consideration for using ILI technologies for delivering coating capabilities to the required pipework internal locations. HSE considers the application technology to be at an early stage of development. Remaining gaps in knowledge include specific efficacy of intended coatings, as well as the technology to apply such coatings in situ with sufficient confidence in application quality control. Failure to apply these mitigations measures to an appropriate standard would undermine or potentially invalidate integrity management assumptions.

HSE notes that the level of assurance that can be gained from experimental data when considering potential long-term real-world exposure is limited. Operational learning, supported by further research, will be key to validating the evidence

26 Inhibition of Hydrogen Embrittlement Effects in Pipeline Steels - Technical Report - Rosen, 2024

provided. It is likely that current integrity management approaches should support this validation if adapted to hydrogen service.

The evidence as provided acknowledged that further work is required to support the case for the long-term conversion of the NTS pipeline network to hydrogen service to provide greater confidence on asset integrity. This extends to assets such as PRI's, valves and filter skids where a notable percentage of some assets that have been removed from natural gas service to be tested for compatibility with hydrogen have proven to leak or malfunction, with some limiting the test scope due to asset failure.

Hazardous Areas Impact Assessment

Due to the differing gas properties between natural gas and hydrogen, gas installations will have to undergo re-assessment in accordance with DSEAR which will likely require modifications to hazardous area zoning and equipment items in order to remain compliant. Hazardous area impact assessments have been undertaken for two sample installations by DNV on behalf of NGT. These assessments focussed upon a Pressure Reduction Installation at Tirley and compressor station at Felindre, (reference Tirley PRI Hazardous Area Impact Assessment²⁷ and Felindre CS Hazardous Area Impact Assessment²⁸) with conclusions further supported by evidence submissions - Hazardous area impact mitigation Phase 1²⁹, Hazardous Areas Updating for Hydrogen, H21 Hazardous Area Zoning Summary Report³⁰ and H21 ATEX-SR25 Summary Technical Report³¹.

There is a clear legislative requirement to ensure that equipment is suitably assessed as being compliant with the gas composition. A change from natural gas to hydrogen would lead to a requirement for equipment to be upgraded from gas group IIA to IIC in line with ATEX certification. This would be a key element of the design review and management of change process that network operators would have to undertake.

Due to the properties of hydrogen gas, especially the wider flammable limits, the defined hazardous areas under DSEAR around equipment items and, in particular, the various vents require the Hazardous Zones to be considerably increased. For example, horizontal dispersion radius increasing from 7 m to 30 m for compressor fuel gas vents with fuel gas creep vent horizontal dispersion radius increasing from 11 m to 70 m (reference, H21 Hazardous Area Zoning Summary Report, Tirley PRI Hazardous Area Impact Assessment and Felindre CS Hazardous Area Impact Assessment). This will likely require equipment to be updated to remain compliant with the revised hazardous areas and may present issues where those revised hazardous areas impact on equipment that is difficult to adapt or replace. The

27 FutureGrid – Tirley PRI – Hazardous Area Classification and Impact Assessment, DNV, 2023

28 FutureGrid – Felindre Compressor Station – Hazardous Area and Impact Assessment, DNV, 2023

29 351: Hazardous Area Impact Mitigation Phase 1, Steer Energy, 2024

30 H21 Hazardous Area Zoning Summary Report, Fingleton White, 2023

31 H21 ATEX-SR25 Summary Technical Report, Fingleton White, 2023

potential extension of hazardous areas beyond the site boundaries represents a challenge for the gas network industry to control ignition sources beyond their management. The evidence proposes a range of mitigation that in some instances relies upon considerable site modifications to improve the impact of the revised Hazardous Zones.

The submissions HSE received and reviewed lacked detail on Mechanical Equipment Ignition Risk Assessments. Such assessments may require design changes to major machinery items typically impacting seal design, failure modes and operating temperatures. As such, a Mechanical Equipment Ignition Risk Assessment would be required for all impacted mechanical items such as vent fans and pumps and would be expected to form part of a design review and management of change process. As the evidence submitted did not address these issues, the impact on potential design changes has not been considered.

A change to 100% hydrogen would require a DSEAR review of installations to assess the impact of conversion to operating with 100% hydrogen due to the differing properties and Gas Group (as defined in ATEX) of hydrogen compared to natural gas. There is recognition within the evidence that complex installations such as compressor stations would be required to undergo a design review with potential for major modifications being required to compressor assemblies. The scale of this challenge was not quantified but was recognised as being significant.

For less complex installations such as pressure reduction installations, the DSEAR review would require changes to the identified Hazardous Areas and equipment upgrade to being suitable for Gas Group IIC. Mitigation of the size and shape of Hazardous Areas will require site modification, particularly to pipework routing and geometry. Much larger Hazardous Areas will develop during purging and commissioning activities that would need to be included within operational procedures and suitably managed.

Compression

The NTS uses more than 60 compressor units at 21 compressor stations around Great Britain that are used to maintain the flow of gas at sufficient pressure throughout the gas supply network. Each compressor station comprises two or more compressor units typically powered by gas turbine engines. The compressor stations are located at strategic locations within the NTS pipeline network to ensure reliable supply across the network. There are different challenges to be considered between the repurposing of a gas turbine power unit to operate with a hydrogen fuel gas supply versus the repurposing of the gas supply compressor unit from natural gas to hydrogen.

Gas turbine powered compressors have been developed and operated in various fuel duties over a number of years within wider industry. There are similarities with

such gas turbines and large rotary compressors operating in a variety of applications with those used within the gas networks, providing background knowledge of operation in hydrogen applications, particularly in oil refining. There is the potential that knowledge related to materials and performance characteristics has been gained by the Original Equipment Manufacturers (OEM's) and operators that has some relevance to hydrogen repurposing but has not formed part of the evidence demonstration.

A number of high level and desk-top studies were provided that considered the feasibility of repurposing network compressors. The HyNTS Compression Alpha Technical Report³² commented that the Siemens SGT-A20 gas turbine power unit was capable of operating on up to 100% hydrogen with limited modifications. However, it was not clear within the evidence submission whether this assessment included an evaluation of the potential long-term impacts of hydrogen on the materials of construction and changes to the maintenance and inspection intervals. The compressor package could operate at up to a 50% hydrogen blend but would require a modified compressor unit for higher concentrations up to 100%. The assessment was said to be supported by extensive operation of the SGT-A20 with hydrogen rich fuels (up to 85% hydrogen) since the 1970s/80s in industrial process plant applications. Further details of this experience were included in the report prepared by Siemens as part of the Hydrogen Fuel Gas for Compressors study.

The Technical Summary (Work Package 5 - Task 5.08) of the NGGT and Partners' Feasibility Study of Hydrogen Fuel Gas for NTS Compressors (H2F4C)³³ reported that it is viable to run the Siemens Energy SGT-A20 GTs on blends of hydrogen and natural gas up to 100% hydrogen and that there are historic examples of this type of Gas Turbine doing so without detriment, i.e. operating with up to 100% hydrogen fuel gas supply to the turbine. Details of this evidence were not provided in the report.

HyNTS Project Alpha Phase³⁴ reporting on fire detection and suppression, outlined the technologies and approaches available and in development for gas flame and fire detection and fire suppression. Suppliers were confident in gas detection equipment, although it is not proven on the ranges of potential blends. Detection of 100% hydrogen gas could present challenges due to buoyancy, requiring careful consideration as to detector locations to ensure that the detectors come into contact with the gas upon release. However, the report above did not consider gas detection to be an appropriate primary means of fire suppression initiation due to the impact of ventilation on gas detection efficacy.

32 HyNTS Compression Alpha Technical Report, National Gas Transmission, 2023

33 Technical Summary (Work Package 5 task 5.08) of the NGGT and Partners' Feasibility Study of Hydrogen Fuel Gas for NTS Compressors (H2F4C), SBLC Ltd, 2023

34 HyNTS Project Alpha Phase, Spectrum Fire Protection (UK) Ltd, 2023

The detection of lubricating oil fires in compressor or gas turbine enclosures could be accomplished using established flame detection technology, although the detection of a hydrogen fueled fire using flame detection is still in development and not fully proven or substantiated by the current testing standards. Trials indicated that a hydrogen flame of 50 cm would be detected within 1 second at 10 m compared with a butane flame of 5 cm. At the time of compiling the report in late 2023, HyNTS Project Alpha Phase reporting on fire detection and suppression stated that the larger manufacturers were starting to demonstrate detection with hydrogen flames and were expecting viable products to become available in 2024/2025. This latter demonstration has not formed part of this evidence assessment.

The study on providing fire suppression concluded that CO₂ would probably be the most appropriate suppression agent. However, it was the further conclusion that in the event of a large quantity of gas escaping into a confined space the risk of ignition and explosion would be very significant, and it would be unlikely that a fire could be managed by a suppression system alone. Consequently, the fire management provision would need to be extended to a combined approach incorporating gas and fire detection with isolation of the fuel supply. This could also extend to grid supply to and from the compressor depending on separation and isolation of the gas turbine and compressor units.

The Failure Modes Effects Analysis (FMEA) study, NGT Compressor Station for Hydrogen³⁵ assumed that, for the 100% hydrogen case, all compressor units and lubrication systems will have to be replaced or significantly renewed. The prime movers or drive units (motors or turbines) would be largely repurposed with modifications limited to those that are required to enable use of hydrogen as a fuel source in the case of gas turbines. As a result, it was assumed that there would be a low risk of compatibility issues with compressors being redesigned as being fit-for-purpose.

The FMEA study identified areas that would require careful engineering and potential further mitigation measures such as those related to the need for higher operating speeds with increased potential for vibration, overheating, and wear out through the compressor train. HSE considers that increased speed requirements would require bearing design assessment through the compressor train and seal design assessment for increased operating speed and hydrogen service for the compressor.

A degree of modification was advised within the studies as being required to fuel delivery, metering systems and burner design to optimise performance and in order to meet the requirements of DSEAR. Control systems would be required to be modified and other infrastructure such as the exhaust gas outlet and ventilation

35 NGT Compressor Station FMEA for Hydrogen – FMEA Summary Report, DNV, 2024

systems modified to take account of the higher moisture content of the exhaust gas stream and differing ventilation requirements of the enclosure.

The submission 'Feasibility Study of Hydrogen Fuel Gas for NTS Compressors' identified that all 24 operational compressor stations within the National Gas Transmission (NGGT) fleet had been assessed for the potential to host a 100% demonstration hydrogen compression solution. Six sites had been rated as "Medium" potential and five as "High" potential, based upon a series of criteria including economic viability. While the transfer of technology and operating experience from other sectors is available, the specifics and scale of hydrogen fuelled hydrogen transmission compression package provision requires substantial development and modification.

HSE considers that it is, or will be, feasible to develop suitable systems and / or modify those that already exist, although such modifications are likely to be extensive. Compressor design and operation must be carefully matched to the duty and suitably designed for such duty. It would be expected that a full design and project safety assessment would be applied to any compressor package design build and installation, as required by relevant legislation and RGP, pending further design and operability review.

Recompression and venting

The application of venting and recompression in hydrogen service is a key element in pipeline commissioning and for pipeline intervention activities. Compressors are configured to move gas between pipeline sections to either commission or decommission relevant pipeline sections keeping losses to a minimum. Such compressors are typically large packaged systems incorporating an engine (prime mover) to drive the compressor element fuelled by the transmission gas (currently natural gas).

The report Safe Venting and Recompression of Hydrogen³⁶ reported that development of suitable compressor packages able to be powered by hydrogen was at an early stage. The report Safe Venting and Recompression of Hydrogen concluded that equipment was not yet available to cater for 100% hydrogen and the gas compositions that occur during conversion operations. Prime movers (internal combustion engines) remain having to be developed to run at varying gas compositions and be suitably packaged with compressor modules. The proposed NGT replacement compression systems are specified to only be suitable for hydrogen content up to 12% based upon compressor design limitations. Modifications are required for higher hydrogen concentrations, which would currently render the associated equipment package too wide for general road transportation.

36 Safe Venting and Recompression of Hydrogen – Final Technical Report, Wood Plc, 2024

The report noted that venting of pipeline inventory can be accomplished via a flare system to limit environmental impact and the generation of a flammable atmosphere local to any vent. The report proposes the use of enclosed flare systems to provide efficient disposal of vented gas and suppress noise emissions. However, the report identifies a number of safety concerns associated with venting that require more research.

From the evidence provided it is clear that the provision of suitable compression systems requires considerable development by system suppliers. This includes the development of suitable internal combustion engines capable of being fuelled by a range of hydrogen compositions as well as 100% hydrogen. There will be differing scenarios during any repurposing i.e. conversion and purging from natural gas to 100% hydrogen compared to use of such systems as part of a 100% hydrogen network.

The HSE review identified a concern associated with the use of enclosed flare systems in general where such systems may pose an increased risk of delayed ignition leading to detonation and burn-back. This issue had been identified within the submission with mitigations such as continuous pilot flames and initial inerting being discussed, but it will require increased scrutiny during any design phase and prior to implementation. Although alternative systems such as flare stacks may be used, enclosed flares have a number of advantages including noise suppression during flaring activities.

Line-Pack

Line-Pack refers to the storage of gas at elevated pressure in the high-pressure network. This surplus gas can then be made available to meet the peaks in demand.

It had been intended to include a Line-Pack assessment within the LTS Futures live trial in order to validate Line-Pack modelling on a live system at the nominal operating pressure of the LTS. However, due to limitations placed upon the Maximum Allowable Operating Pressure (MAOP) following the pipeline assessment for hydrogen service, the Line-Pack trial would be limited at the defined MAOP. Flow and pressures will be monitored throughout the pipeline intervention welding trials, as per LTS Futures Technical Note 10367906-TN01³⁷. However, this won't necessarily be representative due to the limitations on MAOP, although the calculated volume of the pipeline could enable a degree of modelling to be undertaken. As the LTS Futures Trial is not due to go live until mid-2025, this modelling has not been included in the evidence assessment.

The impact of hydrogen embrittlement, particularly on higher strength steels, with reductions in fracture toughness and increased fatigue crack growth rate, means

37 LTS Futures – Technical Note (Doc. Ref. 10367906-TN01), DNV, 2024

there will be limitations on the ability to contain similar qualities of gas within the network through the application of Line-Packing.

Overall, HSE considers that there remains uncertainty on the application and capacity of line-packing within the network due to limitations on maximum allowable operating pressure reduction and fatigue life in hydrogen service that requires further clarity. The full extent of available capacity will be informed by specific construction conditions and operation of NTS assets across the network and any specific damage mitigation measures as may be deployed.

Purging

Purging is the term applied to enable the transition from one gas to another within process equipment or pipework. Examples of where it is necessary to carry out purging activities would be to replace a flammable gas with air to enable works to be carried out, replacing air with a flammable gas by way of recommissioning, or switching from one flammable gas to another such as natural gas to hydrogen. Due to the nature of flammable gases and especially hydrogen, it is often necessary to initially transition to an inert gas prior to allowing air, containing oxygen, into a pipework system, referred to as indirect purging. Purging from flammable gas to air or back to flammable gas is referred to as direct purging.

Two flammable hazards are created during purging operations; firstly, the development of a combustible gas mixture within a piping system that can ignite or burn back from an external or internal ignition source and secondly, the ignition of the venting flammable gas at the vent outlet as the flammable gas mixes with air. Hydrogen being more ignitable than methane and exhibiting a much wider flammable range therefore potentially poses higher risks than that of natural gas.

The proposed purging process to be applied for conversion to hydrogen service was studied within the HyPurge³⁸ and HyPurge Safe Tooling³⁹ programmes. Although these trials related to the distribution network up to 250 mm nominal bore, as related to the H100 project, the learnings are transferable to the NTS and LTS procedures with theoretical purge tables calculated up to 1.2 m diameter pipe. The high-level conclusions identified that hydrogen purges from air to hydrogen were generally more efficient than natural gas purges with the total volume of air-fuel mixture created in a purge involving hydrogen likely to be less than that involving natural gas, with purges from both fuel gases back to air having a relatively similar performance to each other.

Hydrogen purges are generally larger and more ignitable than natural gas purges. The flammable volume of air-fuel mixtures created inside the pipe during a purge involving hydrogen is likely to be greater than one involving natural gas. This is due

³⁸ HyPurge, Steer Energy, 2022

³⁹ HyPurge Safe Tooling, Steer Energy, 2023

to the much higher flammable range of hydrogen i.e. 4% to 74% in air as opposed to 5% to 15% natural gas in air, meaning that the volume of mixture that is flammable inside the pipe will be greater for a hydrogen purge than for natural gas. The total volume of flammable air-fuel mixtures generated outside of the pipe during a purge involving hydrogen was determined to be less than that involving natural gas due to the rate of hydrogen diffusion. However, due to the low ignition energy and wider flammable limits of hydrogen there would be a higher risk of ignition at the purge outlet.

Evidence submissions provided details on the use of flame arrestors. Although flame arrestors are utilised during some natural gas purge procedures, for hydrogen, the gas networks industry raised some concerns that they would introduce a flow restriction and require careful sizing and design. The development of purge tables for use with hydrogen, which included purge velocities, pipe diameter and purge length limits, were calculated to maintain suitable interface conditions and limit mixing and volume of the flammable interface.

The evidence demonstrated that, on smaller pipework, keeping the gas exit flow velocity above the flame speed would prevent the flame entering the pipework. Internal ignition sources were not considered to be a significant risk although static discharge and heat generated by particulate matter within the stream had been identified within the literature study.

The HyPurge Safe Tooling study included ignition tests with a range of lengths of 63 mm and 90 mm bore PE pipework. The recorded overpressures for hydrogen were greater than those for natural gas. The 90 mm x 50 m test presented a much greater volume of potentially flammable gas, exacerbating the reaction with hydrogen compared to natural gas. All ignitions were contained within the pipework. It was accepted by the study that the internal ignition scope was limited, with further trials using improved instrumentation recommended within the study conclusions.

The presence of dead-legs such as isolated or capped supplies, as well as certain pipework geometric features, may present some challenges with respect to purge efficiency. The gas networks had commented that the trials demonstrated that such features made more of a difference with methane than hydrogen so it was considered by the gas network industry that there would not be a greater risk presented by the hydrogen case.

Further testing of the purging of the local distribution pipework was reported within the H21 Phase 2A Testing submission Minimum Purge Velocity Report⁴⁰ by DNV that tested minimum purge velocities and validation of purge equipment such as vent and purge riders.

40 H21 Phase 2A Testing – Part A – H21a: Minimum Purge Velocity Report, DNV, 2023

The trials included a number of purge scenarios including both indirect, direct and natural gas to hydrogen purges on 125 mm and 315 mm polyethylene (PE) pipe lengths. This investigated stratification, and the extent of mixing zones formed during the purge of the gases in pipes in relation to the purge speed. All purge tests were presented as successful.

The evidence concluded that:

- Indirect purging of low-pressure hydrogen pipes can be safely and efficiently conducted using the same size riders and vents as those already used for natural gas direct purge operations.
- Conversion purging from natural gas to hydrogen can also be conducted safely and efficiently using the same rider and vent size combinations as used for natural gas purge operations.
- Existing equipment used for carrying out purging operations was deemed to be generally acceptable for use with hydrogen apart from some exceptions e.g. such as the proposed purge stack HyPurge Safe Tooling which had been modified and fitted with a purge whistle, sample point and variable orifice cap.

Two further evidence submissions, H21a Commissioning and Decommissioning⁴¹ and H21 2b Purging and Venting⁴², covered trials at the Spadeadam Microgrid test facility. These trials included commissioning and decommissioning of straight mains, branched networks, and service pipes in each of the pressure tiers. Pipe diameters above 32 mm were commissioned and decommissioned indirectly with pipe diameters under 32 mm purged directly. Conversion style commissioning was also trialled in Intermediate Pressure, Medium Pressure and Low-Pressure tiers converting pipes previously commissioned with natural gas to contain 100% hydrogen.

Considering network equipment such as pressure reduction installations (PRIs), the evidence submission identified the need for indirect purging prior and post invasive maintenance. HSE noted within H21 Phase 2B T&M Pressure Regulation and Maintenance⁴³ that while the regulator used for the trial had adequate purge points to allow for effective indirect purging, that was not the case for all the PRIs. The evidence recommended that the requirement for indirect purging of equipment should be considered when developing new PRI installations with additional vent and purging points allowing the purging process to become streamlined for the operators completing purging operations in a safe manner. Additional purge and rider points would likely be required for existing asset assemblies where there are insufficient

41 H21 Phase 2A Commissioning and Decommissioning Operations, DNV, 2022

42 H21 Phase 2B Purging and Venting, DNV, 2023

43 H21 Phase 2B T&M Pressure Regulation and Maintenance, DNV, 2023

purge and rider points when subject to invasive work, i.e. requiring modification to live systems.

Although the evidence pieces on purging generally applied to the distribution networks the findings are relevant to be applied to purging procedures carried out within the NTS, dependent upon equipment or asset type and geometry. Purge tables modified for hydrogen had been developed as applied to current natural gas IGEM procedures such as Purging Operations for Fuel Gases in Transmission Distribution and Storage found in IGEM/SR/22. There will be additional inherent risks associated with potential ignition within larger bore piping systems. However, purge velocity remains a critical parameter as does the choice of purge procedure to be adopted. HSE has not seen the evidence submissions developed into a procedure to be applied as part of this assessment. However, development of a suitable procedure or procedures for purging NTS assets is not considered to be a barrier to repurposing with current technology and knowledge able to be applied.

Conclusions

HSE considers, that it is potentially feasible to convert the use of the NTS from the transportation of natural gas to hydrogen. However, there are a range of outstanding issues that the gas network industry would need to address. These include continued review of asset identification and assessment of asset construction, condition and operation. The reassessment and management of revised hazardous areas requires careful consideration, particularly in relation to where hazardous zones extend beyond site boundaries. Pipeline intervention activities, including decommissioning and recommissioning, hot tapping and on-line isolation procedures require development of suitable procedures and validation of operations.

However, while the evidence demonstration supports near term potential use of the NTS, the longer-term impacts from hydrogen service remain to be determined. The level of assurance that can be gained from experimental data when considering potential long-term real-world exposure is limited. Operational learning, supported by further research, will be key to validating the evidence base provided. It is likely that current integrity management approaches should support this validation if adapted to hydrogen service.

HSE notes that the use of line-pack (for storage) of hydrogen within the NTS will likely be compromised due to potential restrictions placed upon maximum allowable working pressure and fatigue life of pipeline assets. The implications for the resilience of hydrogen gas supplies would need to be considered.

Further outstanding issues that the gas network industry would need to address are considered below.

- Overall, HSE considers that the evidence has provided good insight into how pipework and other critical assets will perform in hydrogen service. However, there are areas that require further development, and it must be acknowledged that the sample size of components tested with the evidence trials is relatively small.
- For asset identification and condition assessment there are remaining questions in relation to the application and efficacy of ILI technologies. These relate to identification of specific material degradation mechanisms associated with hydrogen and construction flaws. The successful deployment of ILI requires further development in application and material compatibility, but the challenges are not considered insurmountable.
- It will remain critical to ensure that ILI and similar technologies are not used beyond that for which they have been validated through development and trial runs with known material flaws and damage. It should be acknowledged that limitations currently exist with deployment of ILI tooling within the existing natural gas infrastructure. As such a holistic approach to asset integrity is required, i.e. deployment of additional technologies and techniques dependent upon targeted degradation and risk.
- Concerning the performance of NTS Assets in hydrogen service, HSE considers that flow metering systems require further development to ensure stability and accuracy over the required flow ranges. These systems need to be sensitive to gas properties and composition as well as exhibiting varying turn-down capabilities and accuracies. Whilst flow rate is typically an operability related issue, the development of flow meters should ensure that their materials and design are compatible with hydrogen service. However, various flow metering technologies have been in use in various capacities and applications within industry for many years. As such, flow metering is mature and well understood and further development should not be considered a barrier.
- On asset integrity, HSE has concerns over the failure rates and sample size of the repurposed ancillary assets tested. The sample was relatively small compared with the general population of such assets across the NTS and some assets could not be tested effectively due to their condition. As such it may be indicative of a wider issue with such asset integrity. Leakage and asset failure evidenced would be considered intolerable in service and this therefore represents an evidence gap. HSE concludes that the gas network industry would have to implement a review of each equipment type and assess for adequate integrity, function and design. General industry expectation would be that control valves, regulators, overpressure protection devices and filters, would be sized and set according to the operating conditions and process medium in accordance with RGP, whilst the sizing and specifying of equipment for use with hydrogen within some industry sectors is established, specific RGP as relates to the conversion of

the gas supply network remains at an early stage of development. Therefore, all such assets would need to be assessed for suitability. It should be acknowledged that this evidence gap gives rise to the risk that integrity checks may indicate a requirement for considerable refurbishment of assets for hydrogen service.

- HSE considers that the HyNTS Pipeline DataSet could provide the basis for the development of the required data for pipeline analysis and what actions will be required to close any gaps in such data. Asset assessments may indicate lower maximum allowable operating pressure and shorter fatigue life that would impact transmission capacity as well as storage through the use of line-pack.
- HSE has concerns over the efficacy of applied coatings by way of preventing or reducing the impact from hydrogen embrittlement. The evidence submission Technical Summary Report of the SIF Discovery project (10022648) Hydrogen Barrier Coatings for Gas Network Assets⁴⁴, describes how metallic materials applied by either electroplating, hot dipping or metal spraying techniques, provide the optimal barrier against hydrogen diffusion. Although described as mature technologies there is limited consideration as to how such techniques could be applied practically for in-situ equipment. Concerns relating to how such coating technologies could be applied to the internal services of buried pipelines and equipment include the efficacy of the means of application, with preparation post application inspection and quality assurance as well as on-going maintenance being critical. These areas of concern have not been suitably evidenced and therefore remain as an evidence gap.
- Due to the differing gas properties between natural gas and hydrogen, installations will have to undergo new assessment in accordance with DSEAR that will likely require modifications to equipment items to achieve compliance. It is also likely that there will be an increase to the hazardous area zones.
- The potential extension of hazardous areas beyond the site boundaries represents a challenge for the gas network industry to control ignition sources beyond their management. The evidence proposes a range of mitigations that, in some instances, relied upon considerable site modifications to improve the impact of the revised hazardous zones.
- In addition, the gas network industry will need to manage the development of much larger hazardous areas during purging and commissioning activities that need to be included within modified operational procedures. There is a clear legislative requirement to ensure that equipment is suitably assessed as being compliant with the gas composition with a requirement to upgrade ATEX certification from gas group IIA to IIC (due to hydrogen being

⁴⁴ Hydrogen Barrier Coatings for Gas Network Assets - Technical Summary Report: Hydrogen Barrier Coatings - Ultima Forma Ltd., National Grid Gas Transmission, 2022

classified as group IIC). This would be a key element of the design review and management of change process that network operators would have to undertake.

- It would also be the regulatory expectation that mechanical ignition risks would be considered as part of a DSEAR assessment.
- On compression, HSE concludes that it appears feasible to develop suitable compressor systems and / or modify those that already exist for use with hydrogen, although such modifications are likely to be extensive. HSE acknowledges that, while further development is required, it is considered that viable solutions could be available.
- On recompression and venting, HSE concludes that suitable recompression equipment to be used during pipeline decommissioning and commissioning procedures is not currently available for use with 100% hydrogen. Extended timelines for development and deployment have been indicated by the gas network industry but a roadmap to resolution has not been fully developed. Unavailability of packaged machines capable of operating with higher blends of hydrogen, up to 100%, and the limited operational profile of existing equipment will lead to additional venting and use of flare systems during pipeline intervention and conversion activities.
- There is a requirement for further assessment of suitability to be applied during any design phase and prior to implementation of the use of enclosed flare systems.
- HSE concludes that the use of line-pack (for storage) of hydrogen within the NTS will likely be compromised due to potential restrictions placed upon MAOP. This could have implications for the resilience of hydrogen gas supplies.
- HSE concludes that development of suitable procedures for purging NTS assets is not considered to be barrier to repurposing, although thresholds for applying specific techniques will likely vary. Suitable operational procedures will be required to be developed and there will likely be changes required to equipment and tooling.
- Due to sensitivities associated with assessment parameters and variations in quality condition and operating history of NTS (and LTS) pipeline assets, it is considered critical that individual assets are subjected to assessment. These assessments would need to be based upon sufficient data of adequate confidence, quality and detail to enable definition of safe operating limits prior to repurposing. Where such data is not available further research, investigation or study would be required and / or the application of further mitigation or restriction of the allowable service conditions imposed.

Section 8. The Local Transmission System

It is potentially feasible to convert the use of the LTS from the transportation of natural gas to hydrogen.

However, while the evidence demonstration supports near term potential use of the LTS, the longer-term impacts from hydrogen service remain to be determined.

The level of assurance that can be gained from experimental data when considering potential long-term real-world exposure is limited. Operational learning, supported by further research will be key to validating the evidence base provided. It is likely that current integrity management approaches should support this validation if adapted to hydrogen service.

There are a range of outstanding issues that the gas network industry would need to address. These include gaps in knowledge relating to the suitability and condition of critical equipment such as pressure reduction installations that are integral to the pipeline network.

Introduction to the Local Transmission System (LTS)

The Local Transmission System (LTS) takes gas from the National Transmission System (NTS) and transports it more widely within an area, enabling the gas to then be distributed locally within the Local Distribution System (LDS). The LTS, like the NTS, is operated at pressures above 7 barg, but does not generally reach the higher pressures seen in the NTS.

HSE's evidence assessment for the LTS

LTS Futures Pipeline Trial

SGN submitted evidence to HSE that was considered by the gas network industry to be relevant to the broader assessment of safety for hydrogen, beyond those specific to the running of the LTS Futures live trial itself. At the time of writing, the trial has not gone live but is expected to commence in 2025 meaning the evidence assessed does not include any operational data or trial evaluation.

The LTS Futures trial is based on transporting hydrogen in what the networks have presented as a typical high-pressure pipeline that has a reassessed Maximum Allowable Operating Pressure (MAOP) of 26 barg. Prior to being mothballed the pipeline had transported refinery tail gas from the Grangemouth Refinery to Granton.

The composition of refinery tail gas, although containing methane, can vary and contain other substances such as hydrogen and ethane (C₂H₆), as well as other impurities such as hydrogen sulphide (H₂S). The actual composition of the refinery tail gas transported in this instance has been defined within evidence submission LTS Futures Grangemouth to Granton Pipeline Assessment of TD/1 Compliance⁴⁵, that also identifies use for transporting towns gas from Granton. The corresponding compositions are detailed at table 5-5 and 5-6 of LTS Futures Grangemouth to Granton Pipeline Assessment of TD/1 Compliance with no reference to H₂S, therefore reducing the historic degradation threat scenarios.

The SGN submission, LTS Futures Technical Note: How representative of the LTS is the Grangemouth to Granton Pipeline provides evidence as to how representative the LTS Futures trial is versus the wider network. The Granton to Grangemouth pipeline uses differing pipe sections. These are seamless and spiral welded line pipe grade X52 steel and of differing wall thickness. The pipeline was constructed for a specific duty that was not the conventional conveyance of natural gas but for the transport of refinery tail gas, having an initial hydraulic test pressure of 84.7 barg. The initial design pressure was 24 barg with an operating pressure of 15 barg, as defined within the repurposing assessment and report by PIE⁴⁶. As the pipeline conveyed refinery tail gas, there is a potential degradation threat from H₂S, which may have been in the gas and may affect some legacy pipeline assets.

The pipeline will not be subject to excessive fatigue conditions during the live trial as no fatigue assessment could be completed on the pipeline due to a lack of historic operational data. The pipeline has not and will not be subject to In Line Inspection (ILI) prior to the trial. The live trial is scheduled to run for a limited period and was not live at the time of this evidence assessment, therefore the results from the trial and any operational data are not included in this assessment.

The development of the live trial was informed and supported by off-site testing of materials and pipeline intervention operations, which has contributed towards the general operational safety evidence demonstration. Metallurgical studies had been carried out, associated with the LTS Futures project in support of repurposing to hydrogen. HSE concluded that the studies used appropriate samples from recovered pipework sections representative of the Grangemouth to Granton pipeline. The Critical Stress Intensity in Hydrogen (KIH) findings were awaiting further analysis prior to completing conclusions. These findings were not completed by the time of HSE's assessment.

45 LTS Futures Grangemouth to Granton Pipeline assessment of TD/1 Compliance, Pipeline Integrity Engineers Ltd. (PIE), 2023

46 LTS Futures – Repurposing Report for the 18" Grangemouth to Granton Pipeline for 6 Months Live Trial, Pipeline Integrity Engineers Ltd. (PIE), 2024

Trials relating to the application of Stopple and BISEP tooling, used to isolate a live line or install an additional tapping within a live line, had been undertaken with some degree of success in terms of introducing new purging capabilities to the tooling and successful drilling. However, there were some difficulties in securing and maintaining adequate line isolation. There was some justification provided, and it was considered within the evidence that the techniques could be further developed and improved with some of the issues reported as relating to the trial set-up.

Hot works trials were also carried out with reference to Under-pressure Welding in Hydrogen Pipelines⁴⁷, that aided the development of suitable weld procedures. Two split tees and a repair sleeve had been welded under hydrogen flow conditions as well as the installation of a grouted tee. One welded tee and the grouted tee were then used within further fatigue trials with the other welded tee used for weld procedure qualification.

As discussed within the Velocity Design with Hydrogen submissions, due to hydrogen gas not having the same energy density as natural gas, the volume of 100% hydrogen flowing through the network would have to increase by approximately 3 times to deliver energy at an equivalent rate to natural gas, and up to 4 times at higher pressures, such as 70barg. This required increase in flow would require a substantial increase in the velocity of gas flowing within the network, and/or a substantial increase in operating pressure. There is currently a nominal maximum velocity of 20 m/s imposed to reduce the risk of debris within the pipes becoming airborne and causing wear to pipeline components, with a higher velocity limit of 40 m/s applied to pipeline assets assumed to be in clean (filtered) service.

Debris entrained in the flow can impact pipe walls and internal features causing degradation, typically erosion. Such debris present within the system can be due to the original production and use for towns gas as well as other origins such as corrosion and pipeline interventions. Debris is more prevalent within the lower pressure tiers.

Higher velocities through the network may also increase noise levels and cause excitation of some pipeline and equipment elements leading to increased levels of vibration that could contribute to fatigue and hence premature failure.

A series of initial studies had been undertaken under the Alpha phase Velocity Design with Hydrogen submission⁴⁸, which looked at a number of work packages (WPs) looking to further extend the development of research via the Beta Phase research trials. Several areas of study directly impacted upon the potential to affect asset integrity:

47 LTS Futures WP1: Under-pressure Welding in Hydrogen Pipelines, DNV, 2024

48 SIF Alpha Phase: Velocity Design with Hydrogen – Summary Report, DNV, 2023

- WP2A (Alpha Phase)⁴⁹ included the study of erosion within hydrogen systems, providing data and insight on predicted erosion within pipeline systems operating up to 40 barg. The work concluded that operation at 100% hydrogen could potentially increase erosion due mainly to the required increase in velocities to provide equivalent energy when compared to natural gas.
- WP3 (Alpha Phase)⁵⁰ erosion studies were extended to include testing with hydrogen charged samples. Erosion in such samples may be enhanced, such as by producing a newly scoured surface that may potentially increase the possibility of hydrogen diffusion into the pipe wall leading to localised embrittlement that may enhance erosion susceptibility. The study had found no synergistic impact of embrittlement and erosion on hydrogen charged samples. This WP indicated that further testing was planned to supplement this evidence within the Beta Phase of the Velocity Design with Hydrogen trial.
- WP2B (Alpha Phase)⁵¹ looked at the potential increase in noise and vibration due to increased velocities that were likely to occur using 100% hydrogen and concluded that there were considerable differences in behaviour between the two gases due to their differing properties.
- Increasing blends of hydrogen can increase the level of flow induced vibration, becoming increasingly significant towards flows at 100% hydrogen. Typical above ground gas pipework is considered to be well supported and accessible so should result in absolute vibration related Likelihood of Failure (LOF) occurrences remaining low. Buried pipework is generally considered to be at minimal risk of flow induced vibration due to the support and damping afforded by the surrounding soil. PE pipework would also be expected to have the increased damping inherent to polymer materials, therefore reducing any vibration which might occur.

The minimum size (nominal bore) of dead-leg side branches, where flow induced pulsation is likely to occur, is reduced. This brings more side branches into scope of being at risk of frequency shift potentially increasing likelihood of excitation occurring leading to vibration induced fatigue.

The sound power level generation was predicted to increase with increasing proportion of hydrogen, with potential high frequency acoustic excitation occurring downstream of regulators. This increase was described as being modest, leading to minimal increase in risk when LOF assessment of downstream welded discontinuities is evaluated. Pipework noise generated by the gas flow was predicted

49 SIF Alpha Phase: Velocity Design with Hydrogen – Work Package 2A Test Plan Development – Erosion, DNV, 2023

50 SIF Alpha Phase: Velocity Design with Hydrogen – WP3 – Laboratory Testing, DNV, 2023

51 SIF Alpha Phase: Velocity Design with Hydrogen – Work Package 2B Test Plan Development – Vibration and Noise, DNV, 2023

to significantly rise, demonstrating an increase of 23 to 30 dB at 100% hydrogen. As a consequence, the amount of pipework that will require noise attenuation safety features is likely to increase.

The evidence from WP2B Alpha Phase reported the risk of failure due to vibration of intrusive flow elements (e.g. thermowells) showing a significant increase with hydrogen at an equivalent energy delivery rate. The report concluded that 100% hydrogen would require a gas velocity reduction of between 3.2 and 4.0 times (up to 70 barg) to avoid the risk of experiencing resonant excitation, or the redesign and replacement of such components.

The later Beta Phase study, WP2 Particle Transportation Tests and CFD Modelling Interim Report⁵², intended to provide validation between Computational Fluid Dynamics (CFD), British Gas modelling generated data and data obtained through physical trials.

This evidence piece concluded that initial comparison between the CFD modelling and British Gas modelling indicates results are similar for both particle rolling and flight velocities for 100% hydrogen at 2 barg.

Using the particle test facility at Spadeadam with 100% hydrogen and 100% natural gas at 2 barg and 40 mbarg, initial experimental results indicate that particle transportation occurred at lower velocities in natural gas than for hydrogen. The experimental data identified that rolling and flight of particles occurs over a range of velocities and there is no specific velocity to instigate rolling or flight. Tests were performed at services for hydrogen. A limited amount of sand was observed to travel up the service compared to the main. Both experimental data and modelled predictions indicate that the majority of particles are mobile at the standard maximum natural gas velocity of 20 m/s, thus an increase in velocity to 70 m/s with hydrogen should not result in an increase in particle transportation. The study indicated that the mitigations used for natural gas should still be effective for hydrogen service.

HSE considers that there are a number of issues identified, particularly related to increased vibration and noise, that require further study and suitable measures developing to ensure that there is no increase in likelihood of failure of critical components or the containment boundary. Erosion remains a further concern as, although it has been indicated that particles are in flight at the accepted IGEM limit of 20 m/s, there is limited assessment of the increase in kinetic energy of the particles travelling at the increased velocity to provide equivalence in energy transportation. There remain evidence gaps in relation to the impact higher velocities within the networks will have on equipment and asset integrity.

52 SIF Beta Phase: Velocity Design with Hydrogen – WP2 – Particle Transportation Tests and CFD Modelling Results – Interim Report, DNV, 2024

HSE recognises that the metallurgical studies undertaken before the live trial used typical recovered materials from the networks and samples recovered from the Grangemouth to Granton pipeline system. The data and fatigue studies provided good data. However, further evaluation or sensitivity studies to determine material performance would need to be undertaken for the less common material grades. Attributes to be considered would include line pipe sizes, varying operational duties, potential differing environmental conditions, age, and varying degradation mechanisms.

As the Grangemouth to Granton pipeline carried refinery gas, there is the potential for stress corrosion cracking due to H₂S. Some legacy assets having seen coal gas service could be similarly affected. This requires further assessment and clarification as to any potential impact in hydrogen service.

Original non-destructive testing reports were available for the LTS Futures trial but not the original X-rays. Specific defect sizing could not therefore be assessed and considered for hydrogen duty. Suitable pipeline assessment is a crucial factor for future assessment of LTS assets prior to repurposing. When data on design, installation quality and service life is deficient there will be less confidence in its integrity. In these circumstances a more conservative approach would be required to assessment, which may lead to less margin on operation. Additional inspection and/or application of more sophisticated assessment may be applied to mitigate any lack of data. It was understood by HSE that the HyNTS Pipeline Dataset study purpose was to identify data required and available and apply a suitable assessment.

HSE considers that LTS assets are relatively well documented with a good degree of confidence in the data on asset type and location. The LTS Futures project should provide a good level of understanding on the application of assessment of the current and installed condition of the subject pipeline. Additionally, it will provide a review of the construction quality sign off for welding, weld procedures and non-destructive examination (NDE). These can then be applied to assessment of the wider LTS assets. The LTS Futures Project, along with the output from the HyNTS Dataset study⁵³, should enable a sound judgement to be made by the operator of LTS pipeline systems as to the suitability for repurposing to hydrogen service, allowing them to identify any necessary remediation or mitigation that may be required. The Grangemouth to Granton pipeline is typical in design materials and construction of many LTS pipeline assets. The operational history of this asset deviates from typical LTS assets having been installed to convey refinery tail gas with a differing composition to that of natural gas. The trial will allow for further assessment and validation of pipeline intervention operations that is applicable to the wider LTS asset population.

53 HyNTS Pipelines Dataset Alpha Phase: Final Technical Report, Rosen, 2023

LTS pipelines would require specific assessment to enable repurposing to hydrogen, with the current understanding being that there may be restrictions on Maximum Allowable Operating Pressure (MAOP) and fatigue life in hydrogen service, dependent upon specific assessment findings.

Evidence submissions related to behaviour of barrier coatings and efficacy of Impressed Current Protection (ICP) systems derived a number of conclusions, but there remain questions as to how such conclusions from the evidence pieces will be applied across the networks and to specific assets.

The potential use of barrier coatings to reduce the impact of hydrogen embrittlement at weld locations was considered within evidence submission Technical Summary Report of the SIF Discovery project (10022648) Hydrogen Barrier Coatings for Gas Network Assets⁵⁴. As discussed in the NTS section, metallic materials had been determined to provide a more effective barrier against hydrogen permeation than applied polymers. The methods of application for such materials, as described, included electroplating, hot dipping or metal spraying techniques. Although these application techniques are described as mature technologies, there is limited consideration as to how such techniques could be applied practically for in-situ equipment. Apart from the effectiveness of the coating, there remain concerns over the means of application, with preparation being critical. Suitable post application inspection and quality assurance, as well as on-going maintenance, have not been defined, with these aspects remaining as an evidence gap.

The barrier materials require further development and study, as well as the methods of application quality assurance and validation, before integrity decisions can be applied to pipeline assets. This may impact hydrogen embrittlement mitigation options and may have a consequential impact on Maximum Operating Pressure (MOP) or fatigue assessment if mitigation efficacy is not proven. At this stage, HSE does not consider barrier coating application, assurance and efficacy to have been adequately demonstrated.

The impact of higher hydrogen flowrates within equipment items and filters has been studied at below 7 barg. However, there were no similar studies seen for the LTS and NTS apart from the FutureGrid flow trials that did not address increased flowrates through the LTS. This represents an evidence gap. Further consideration is required on the tolerance of potentially higher velocities within pipework with guidance updated accordingly. The National Hydrogen Safety Assessment⁵⁵ (NHSA) submission recognises the potential of an increase in velocities to increase degradation rates. Degradation mechanisms could include vibration and erosion. The NHSA, considered in more detail in Section 14, acknowledges a review of

54 SIF Discovery Project – Hydrogen Barrier Coatings for Gas Network Assets - Technical Summary Report: Hydrogen Barrier Coatings, Ultima Forma Ltd.; National Grid Gas Transmission, 2022

55 National Hydrogen Safety Assessment (NHSA), Cadent, 2024

Written Schemes of Examination (WSE) should consider all credible degradation threats attributed to repurposing, including fatigue due to vibration due to an increase in velocity.

The NHSA considers the relevance of the LTS Futures trial to the wider LTS, and it proposes a risk assessed approach for individual LTS pipeline assessments. HSE has interpreted this to mean that each pipeline will be individually assessed as indicated previously and as would be the expectation of HSE.

The review of cast iron mains evidence discussed in detail in Section 9 concluded that equipment items containing cast iron remain suitable, subject to review, for operation with hydrogen service in systems operating up to 7 barg. This is based upon the design margin of pressure retaining parts. The evidence presented only considered cast iron up to an operating pressure of 7 barg. Therefore, the evidence demonstration does not support the use of cast iron assets in hydrogen service within higher pressure systems above 7 barg.

Conclusions on the LTS

HSE considers that it is potentially feasible to convert the LTS from the transportation of natural gas to hydrogen.

However, while the evidence demonstration supports near term potential use of the LTS, the longer-term impacts from hydrogen service remain to be determined.

The level of assurance that can be gained from experimental data when considering potential long-term real-world exposure is limited. Operational learning, supported by further research will be key to validating the evidence base provided. It is likely that current integrity management approaches should support this validation if adapted to hydrogen service.

There are a range of outstanding issues that the gas network industry would need to address. These are considered below.

- LTS assets, as with the NTS assets, are considered to be relatively well documented with a good degree of confidence in the data on asset type and location. However, there remains the need to ensure individual pipelines are adequately assessed in relation to material properties, historic operating and process conditions, initial build quality assurance and condition before operating with 100% hydrogen. Acceptable operating parameters need to be confirmed and verified.
- The output from the HyNTS Dataset study should enable a sound judgement to be made by the operator of LTS pipeline systems as to the suitability for repurposing to hydrogen service. This should allow identification of any necessary remediation or mitigation as well as

identifying any requirement to limit maximum operating pressure or pressure cycling to limit fatigue.

- The impact of higher flowrates within equipment items and filters has been studied at below 7 barg. No similar studies have been provided for the LTS (and NTS) at higher pressures. The FutureGrid flow trials that tested assets in hydrogen service did not address the peak increased flowrates that would be required through the LTS. Further study and conclusions are required to be addressed by the gas network industry on the tolerance of pipework to potentially higher velocities, and industry guidance should be updated accordingly. The NHSA has recognised the potential for increase in velocities to accelerate degradation, which could be via vibration erosion. Written schemes of examination should be reviewed and updated as required.
- For live gas operations HSE considers that:
 - further work is required to demonstrate that isolation techniques can be deployed to ensure that adequate isolation of a piping system is accomplished in a reliable and repeatable manner, and the various techniques suitably validated for the pipe material, line size and process conditions accordingly.
 - there are concerns over potential inadequate purges being carried out due to inefficiency of the equipment during purging activities. The issue of purge efficacy also extends to the potential loss of purge during drilling operations where a potential loss of purge within the hot tapping chamber during drilling operations would lead to increased risk. Such an occurrence would be considered within the operational risk assessment and method statement and suitably mitigated. The gas network industry has indicated that further work is being undertaken in this area.
- In relation to barrier coatings as a method for limiting the impact of hydrogen on material properties of higher strength steels, HSE concludes that, although it may be feasible to apply a suitable barrier coating to the critical locations within pipelines to reduce exposure of the substrate to hydrogen, at present suitable technologies have not been demonstrated or proven as described. Therefore, currently there are limited means of practically limiting the impact of potential hydrogen embrittlement within high strength pipeline steels.
- HSE's assessment of the Hydrogen Ready Components studies concluded that the approach provided a robust means of assessing and ranking components and materials for suitability with hydrogen within the limits and scope of the study. The following gaps and concerns remain to be addressed, however:
 - Limiting the scope of the studies to 7barg and below presented knowledge gaps relating to equipment and materials operating within the higher-pressure systems, namely the LTS and NTS. There were other programmes

intended to determine suitability of equipment items such as pressure regulation, filtration, and metering skids for use in hydrogen service with variable results and, in one instance, awaiting commencement of testing.

- The outstanding data submission for the assessment of sealants was of particular concern as this impacts a number of assemblies and piping systems, particularly considering degradation over time. Further studies on sealants applied to pipework screwed fittings had provided variable results. Further testing of sealants should be undertaken for use in hydrogen service and especially with screwed fittings. The findings should be developed to provide appropriate guidance on use of suitable products and application, including any restrictions.
- The justification for use of spring steels within a hydrogen environment was considered to be dependent on the service conditions of a particular asset. Therefore, each asset type will need to be further assessed prior to conversion.
- Some used assets or asset types had not performed well during initial integrity testing and following hydrogen leak testing. Although potentially not specifically related to material compatibility, this raises questions over the level of maintenance and inspection required for such assets for use within a hydrogen environment.
- The gas network industry recognises the need to develop a management process that includes the condition assessment of above ground network assets. The development of IGEM standard TD/22 supports this approach for ensuring such assets are maintained in an acceptable condition, being leak tight and compatible for operation in hydrogen service at the defined process conditions. However, HSE notes that the scope of this standard was limited to trials. Therefore, this standard may need to be developed to support any wider rollout.
- The evidence from WP2B Alpha Phase reporting the risk of failure due to vibration of intrusive flow elements (e.g. thermowells), showed a significant increase to the risk of vibration induced failure with hydrogen at an equivalent energy delivery rate to natural gas. This will need to be considered in conjunction with any conversion and roll-out strategy based upon the anticipated energy demand at 100% hydrogen. If the original intrusive elements are to be potentially re-utilised, the energy demand would have to be reduced by a factor of 3 to 4 times that of natural gas. If the velocity of the gas flow was to increase to give parity in energy transition to that of natural gas, then such devices will likely require reengineering and replacement.

Section 9. The Local Distribution System

It is potentially feasible to convert the use of the LDS from the transportation of natural gas to hydrogen.

However, while the evidence demonstration supports near term potential use of the LDS, the longer-term impacts from hydrogen service remain to be determined.

The level of assurance that can be gained from experimental data when considering potential long-term real-world exposure is limited. Operational learning, supported by further research, will be key to validating the evidence base provided.

While elements of the LDS will be subject to an inspection and maintenance regime, the buried and legacy pipework in the LDS presents a challenge to inspection. Reference has been made to enhanced leakage surveillance, but specific solutions have not been provided.

There are a range of outstanding issues that the gas network industry would need to address, including in relation to the suitability of iron pipes and asset location and condition assessment.

Introduction to the Local Distribution System (LDS)

The supply pressure from the LTS is reduced via several tiers within the Local Distribution System (LDS) to a pressure suitable to be conveyed to individual premises. There are three pressure tiers for the LDS:

- intermediate pressure which operates between 2 bar and 7 bar;
- medium pressure which conveys gas between 75 mbar and 2 bar; and
- low pressure which is for pressures no higher than 75 mbar.

The pressure is reduced through the tiers at pressure reduction stations. Whilst the majority of domestic premises are generally supplied at low pressure, some residential, commercial and industrial premises may be supplied at one of the higher LDS tiers.

HSE's evidence assessment

Material and Equipment Compatibility

There are a range of equipment and asset types incorporating various materials currently used within the gas distribution network that may be impacted by operating with hydrogen.

The submissions Hydrogen Ready Components Phase 1⁵⁶ and Hydrogen Ready Components Phase 2⁵⁷ represent core studies into the material compatibility and functionality of these equipment items and materials for use with hydrogen. The studies relate to equipment used within pressure tiers up to 7 barg.

Materials were considered via three classes. These were metals, polymers and sealants and adhesives. Key properties were defined for each class of material such as strength, toughness, chemical compatibility, and permeation characteristics.

Phase 1 of Hydrogen Ready Components identified 27 assets that failed the initial assessment (screening) process, out of more than 200 assemblies assessed.

The Phase 2 study sought to reevaluate the initial findings from the Phase 1 study with a focus on the assets that failed the initial screening process. The identified assets were reviewed based upon new information that had become available through further trials activities and research. The Phase 2 report presents test results for a number of materials that were recommended for further testing in Phase 1 in order to better define potential degradation. An example is the reliability of spring steels that are critical to the function of a number of asset assemblies. The results showed “there was no systematic effect of hydrogen exposure on the response of the spring sections to applied stress”.

Compatibility and suitability of various sealants had not been reported. This lack of information on other various sealants represents an evidence gap.

Initial available data on polymeric and elastomer materials had been examined within the Impact of Hydrogen on NTS Polymer and Elastomer Materials⁵⁸ submission. This identified gaps within the knowledge of materials used within the NTS in relation to hydrogen compatibility and made recommendations for the development of suitable databases of material properties and past failure information.

The effect of hydrogen on oils and greases used within a hydrogen environment were captured within the study Impact of hydrogen on NTS oils and greases⁵⁹

56 H21 Hydrogen compatibility of components Phase 1: Final, HSE, 2022

57 H21 Hydrogen compatibility of components Phase 2: Final, HSE, 2024

58 Impact of Hydrogen on NTS Polymer / Elastomer Materials, DNV, 2023

59 Impact of Hydrogen on NTS Oils and Greases, Wood, 2024

submission. Issues included potential build-up of hydrogen within a lubrication system, permeation through seals and any impact that may negate hazardous area classification or mechanical ignition risk assessment. Further study would likely require further development of test methods. There was a need to ensure parity on how Original Equipment Manufacturers (OEM's) provided data on the suitability of such materials in equipment and systems.

The study also sought operating experience from industry sectors that had historic experience of successful operation of process equipment in hydrogen service, namely within industrial gas production and supply companies and the chemical and petrochemical sector.

Trials had been carried out on recovered above ground pressure reduction and filtration assets from the networks. These had leaked when tested for initial integrity as well as following a degree of refurbishment. Some sources of the leakage related to diaphragm seals as well as screwed smallbore (below 2") lines. The Technical Note Assessment of Pressure Regulation and Maintenance⁶⁰ summarised the testing and general performance of selected repurposed above ground Pressure Regulation Units (PRU's) and governors installed within the Spadeadam Microgrid site. The assets underwent planned maintenance activities and refurbishment to prove maintenance procedures and operation. Findings included requirements for additional purge porting to be provided to accommodate indirect purging procedures and there was creep witnessed on all pressure tiers, although performance under flow was stable. The flow rate was capped at the same rate as for natural gas, whereas, in service this would have to be increased to approximately 3 to 4 times that of natural gas for hydrogen. The report recommended that any future trials or rollout should see an enhanced maintenance regime applied initially.

HSE's assessment of the evidence on equipment and material compatibility identified the following gaps and concerns:

- Limiting the scope of the studies to 7 barg and below presented knowledge gaps relating to equipment and materials operating within the LTS (and NTS) higher-pressure systems.
- The data submission for the assessment for sealants was of particular concern as this impacts a number of assemblies and piping systems, particularly when considering degradation over time. Further studies on sealants applied to pipework screwed fittings had provided variable results, with some applications exhibiting a relatively low performance requiring suitable guidance to be amended or provided accordingly, based upon the findings.

60 Technical Note 1521623 - Assessment of Pressure Regulation and Maintenance, DNV Spadeadam Research and Development, 2022

- The justification for use of spring steels within a hydrogen environment was considered to be dependent on the service conditions of a particular asset. Therefore, each asset type will need to be further assessed prior to any conversion.
- Some used assets or asset types had not performed well under initial integrity tests and hydrogen leak testing. Although potentially not specifically related to material compatibility, this raises questions over the level of maintenance and inspection that such assets for use within a hydrogen environment will require. Under natural gas service, assets were subject to Reliability Centred Maintenance (RCM), requiring sound operational experience, although some items were considered to be maintained following identification of a fault, i.e. run to failure. For hydrogen the maintenance approach had been proposed as being applied using a calendar-based system with initial schedules being enhanced whilst operating experience was developed.
- Robust maintenance strategies will need to be developed in support of any roll out. There are many such assets within the gas networks with the initial integrity tests providing some concern on the current condition and leak tightness that will be further challenged on any conversion. Therefore, individual suitability and condition assessment will be a critical element of any conversion policy.

Cast Iron

There are cast iron assets within the LDS such as pipes, valves and filters. Current industry practice (such as ASME B31.12 BCGA CP33) does not support the use of cast iron in hydrogen service. The gas network industry provided evidence that sought to demonstrate that cast iron could be used within an LDS operating with 100% hydrogen.

Due to the status of the guidance and standards advising against the use of cast iron in hydrogen service HSE expected that any gas network industry evidence to demonstrate suitability should be of equivalence to that required to achieve a change to existing established guidance and standards. HSE considered that this evidence should be peer reviewed by an appropriate panel of independent experts with their conclusions published. IGEM undertook the role of managing this peer review process.

The evidence submission, Effect of 100% Hydrogen on Cast Iron Assets⁶¹ focussed upon the specific characteristics and degradation mechanisms associated with aged cast iron. This included anticipated operational conditions such as operating

⁶¹ Iron mains and fittings in hydrogen service, Cadent, 2024

pressure, design margin, ground conditions and physical attributes such as size, length and means of jointing. The study specifically focussed upon the differentials between exposure to natural gas and hydrogen. This accepted that the iron mains were aged but also considered the differing consequences of failure between the two duties.

The work covering cast iron was limited to assets operating at 7 barg or below. The use of cast iron with hydrogen above this pressure has not been evidenced.

The evidence needs to be considered within the context of the imposed Iron Mains Risk Reduction Programme (IMRRP) and Iron Mains Replacement Programme.

These programmes address the potential for failure of cast iron gas mains and the consequent risk of injuries, fatalities, and damage to buildings (defined as incidents). The objective of the Iron Mains Replacement Programme was to decommission all cast iron mains within 30 metres of property over a 30-year period. This programme accelerated the replacement of cast iron mains to a level that was estimated to be as fast as practicable at that time, given the potential risks faced and the resources required.

Following the HSE/Ofgem 10-year review of the Iron Mains Replacement Programme (RR888)⁶² in 2013 the approach to decommissioning was revised, so that only smaller diameter pipes (8 inches and below) were required to be decommissioned, with larger pipes being able to remain in service providing certain actions were taken.

As recognised by the launch of the IMRRP, failures within the current network do occur in natural gas service due to degradation of aged iron pipework.

The evidence provided within the Effect of 100% Hydrogen on Cast Iron Assets reported upon a series of metallurgical tests and examinations applied to representative aged samples of materials extracted from the gas network, apart from Pit Iron where fresh material was required due to the poor condition of the recovered samples. The report included a risk assessment on the likelihood of failure based upon the findings.

The findings from the studies were independently peer reviewed by IGEM. The IGEM panel conclusions were reported separately whilst the gas network industry provided detailed reports covering the test methodologies, conclusions, and risk assessment by the commissioned test house. A gas network industry summary report was also provided in overall conclusion.

⁶² HSE/Ofgem: 10 Year Review of the Iron Mains Replacement Programme, Cambridge Economic Policy Associates Ltd., 2011

The IGEM report (IGEM – Cast Iron Technical Peer Review Group of Iron Based Materials and 100% Hydrogen Report and MRPS Assessment for 100% Hydrogen Report)⁶³ drew a number of conclusions from the Iron Mains and Fittings in Hydrogen Service report and appendices. HSE noted that some had not been included within the Summary report, i.e.

- Interactions between graphite inclusions in the iron structure and gaseous hydrogen and the evaluation of crack growth in corroded sections had been mentioned but not been investigated, and
- although it was recognised that a main is exposed to varying levels of corrosion and loading along its length, the assumption was made that all mains will have already been subjected to corrosion processes on the external surface due to exposure to soil water. It was commented that this was an incorrect assumption.

As part of the peer review process, IGEM considered that the iron mains report statement that: *“there is no discernible increase in the failure frequency of iron mains”* had not been fully demonstrated. However, IGEM accepted, with a number of significant caveats, that it is possible to repurpose malleable iron, ductile iron and cast-iron mains for use with 100% hydrogen.

HSE considers that the gas network industry’s Summary Report made some general assumptions that were not necessarily supported by the findings as reported within the technical reports and IGEM peer review report. Examples included, the gas network industry considering that the cast iron pipework having already been degraded in some locations to a similar level or below what would be expected through hydrogen embrittlement due to soil water corrosion. Consequently, the report concluded that there would be limited impact from use in hydrogen service. HSE considers that this assumption did not provide clarity on potential interaction or coincidence between the two damage mechanism initiators or likely distribution within the network.

It was suggested that exposure to soil water (water content of soils surrounding pipework) would “fully charge” the material thus there could be no further impact due to hydrogen exposure at the distribution system operating pressures. This assumption requires further scrutiny as no evidence was provided to support this assertion. HSE considers prior degradation of pipework due to soil water as being exacerbation of degradation rather than mitigation and considered an ongoing risk.

63 IGEM – Cast Iron Technical Peer Review Group of Iron Based Materials and 100% Hydrogen Report and MRPS Assessment for 100% Hydrogen Report, IGEM, 2024

HSE notes that some omissions from the gas network industry's Summary Report reduces the level of confidence in how IGEMs peer review findings have been taken into account.

Some applied test techniques were not considered to optimise testing of the impact of hydrogen on material properties with particular reference to the strain rate. Tests over shorter periods at greater strain rates would give differing results to those carried out over longer periods at lower strain rates. The gas networks industry's Summary Report concluded that malleable and ductile iron was deemed to not be impacted to any degree by hydrogen exposure. However, there was evidence within the technical report submissions indicating otherwise with the results suggesting that there would be an effect, albeit slow to manifest and of limited impact.

The summary submission concluded that, whilst hydrogen has a 10-30% detrimental impact on the strength of pit and spun cast iron, it is not expected to materially increase the number of gas escapes. The report considered that only 1 in 10 gas escapes were attributed to fractures and it is only the fracture frequency that would be impacted.

HSE considered that the sample sizes were limited with the pit iron samples needing to be obtained from new material. New material was required as operational material in adequate enough condition to facilitate testing was unobtainable.

Fractures were generally considered due to secondary stresses such as ground loading or point loading as opposed to hoop stress due to internal pressure. This is because relatively low stresses are imposed by the internal pressure, which is at or below 2 barg. The networks have, however, proposed that a 50% increase in the failure rate of iron assets would represent a suitable conservative judgement at this stage to provide a degree of conservatism.

HSE considers that the level of conservatism afforded by the assumption of a 50% increase in fracture frequency for pit and cast iron is reasonable based upon engineering judgement. As this figure is based upon engineering judgement, HSE would expect this value to be validated accordingly from operational experience.

In-service cast-iron pipe lengths are relatively short, typically being up to 6 m, with a relatively large number of joints. Consequently, the evidence considered that such joints would afford sufficient flexibility to enable a pipeline to flex with ground movement. It was asserted that this would avoid imparting stress associated with bending, with the movement mitigated by joint flexibility. However, HSE notes that this could lead to joint leakage, although the study did not consider this to be comparable with a pipe fracture in terms of leak rate.

Commentary provided on Gas in Building incidents within the submission, due to joint leakage from cast and spun iron mains, was contradictory. It was presented that

the rate of gas escape from a joint is said to be too low to accumulate within a property and reach a flammable concentration. Conversely, the submission also indicated that, for the sample, the total predicted risk with hydrogen will increase by 7.2%, with joint failures contributing to a greater increase in incidents than corrosion. This effectively increases the level of risk predicted. Further, the effects of higher operating pressures on joint failure risk are also not fully explained.

The total Risk of Incident data presented for cast iron is based upon an 'approximately representative' area of the network. No statistical analysis to that effect was presented so this assertion is not supported by a justification. The figures may be higher in other areas, therefore area-specific risk calculations would be required prior to any conversion.

The gas network industry has proposed that all iron mains that expose members of the public to a risk greater than one in one million per annum of becoming a fatality be replaced (or decommissioned as defined within the IMRRP) prior to conversion. However, The Risk Report Appendix 2 did not describe in detail how the individual risk of fatality is calculated from the Mains Risk Prioritisation System (MRPS) risk tool score. HSE understands that the methodology used is the same as that used for natural gas in the IMRRP. HSE has a number of significant concerns about this methodology when used to calculate hydrogen risk, which are considered in Section 11 on risk assessment.

The leakage detection techniques that would be applied prior to repurposing to hydrogen have not been detailed, nor how equipment replacement decisions would be made. It is assumed that those replacements, as well as those opportunistic replacements when preparing sectors for conversion, would be in addition to the MRPS.

Within the IMRRP there is a three-tier approach which allows a greater focus on risk. Under this tiered system, larger diameter 'at risk' iron pipes will only be subject to decommissioning if either condition or risk assessment or engineering judgement indicates this is justified.

The three tiers of pipe diameter are:

- Tier 1: 8 inches and below (approximately 80% of all 'at risk' iron pipes)
- Tier 2: above 8 inches and below 18 inches (approximately 15% of all 'at risk' iron pipes)
- Tier 3: 18 inches and above (approximately 5% of all 'at risk' iron pipes)

The means of management and monitoring of critical cast iron and legacy assets outside of the Tier 1 threshold would need to be clarified by the gas network industry as well as how the ongoing maintenance and condition monitoring regime will be applied, with leak testing being a reactive measure.

Report recommendations include not replacing large cast iron pipes (greater than 8" diameter), within 30 m of buildings, "unless otherwise justified to do so, because they have Broadly Acceptable level risks". HSE considers the site or area-specific risk calculations referenced could potentially shift risk levels to an ALARP level or indicate a higher level of risk in some cases.

Even with standard mitigation, the Hydrogen in Iron report acknowledges that the Location Specific Risk is up to 10 times higher with hydrogen, but states that this risk falls within the 'broadly acceptable' range. HSE notes that this does not negate the requirement to investigate further risk reduction measures or periodically review ALARP considerations including developments in learning and technology.

However, as will be considered in the risk assessment section of this report, HSE has concerns about the methodology used to calculate the individual risk of fatality. If the methodology were modified to address these concerns, the calculated individual risk would increase. Furthermore, HSE's view is that, just because the individual risk is considered 'broadly acceptable', it does not mean that the risk is automatically ALARP. There is still the necessity to demonstrate that no further practicable mitigations can be applied to reduce the risk.

The evidence indicated that, due to calculated risk levels, the 30 m gas main proximity limit (to properties) would be substantially retained for 100% hydrogen cast iron pipes. This would apply unless individual pipe, or site-specific risk assessment dictates otherwise. The gas network industry have indicated the intention to replace all iron pipes within 30 m where the individual risk of fatality in hydrogen duty is greater than one in one million per annum, before hydrogen is introduced. The North-West is expected to require 43.44 km of additional mains replacement, with the national additional cast iron main replacement figures being estimated in the GB Quantitative Risk Assessment report as being 360 km.

The submission indicates that not all hazards or potential release scenarios for hydrogen are considered within the risk calculations. Several possible release scenarios are foreseeable. The assessment of each leak scenario encountered within the UK network may differ due to its specific location, characteristic of gas release or basis of safety. As such, any distance correction may also vary between each leak scenario. HSE considers that these effects on site-specific risk assessment means that level of iron mains replacement required could be greater than is described in the evidence submission.

HSE does not accept the gas network industry's assertion that protection afforded by the installation of downstream Excess Flow Valves and hydrogen detectors represents a relevant mitigation for the risks associated with cast iron. In the case of detectors these are a reactive measure only.

HSE considers that the general approach to the research and laboratory-based activities was sound and well reported. However, there are a number of outstanding issues and the interpretation of the findings in the submission, and within the summary report, are not fully supported by the evidence.

HSE does not agree with the gas network industry summary report findings that:

- cast iron pipes will not be further degraded by the conveyance of hydrogen to some degree, taking account of the advised significant degrading of properties due to soil water contact.
- there will not be any additional failures due to hydrogen that would have an impact.

However, a failure increase of 50% is a reasonable judgment to be applied. This judgement would be expected to be monitored and verified over time and adjustments made to the QRA as appropriate.

It is accepted by the gas network industry that there will be a requirement that additional iron mains will need to be replaced, beyond those that are already planned to be completed by the end of 2032 as part of the Iron Mains Risk Reduction Programme. This is considered within the GDN Hydrogen Risks Mitigation submission⁶⁴ (this submission is considered in Section 12).

The networks have proposed that all remaining cast-iron assets, and in particular larger mains, would be subject to a “condition assessment” with remediation, repair or replacement prior to conversion. There has been insufficient evidence provided so far relating to what inspection and surveillance techniques will be deployed, and what maintenance regimes will be implemented over and above the current approach, to enable HSE to comment on its suitability. The gas network industry suggested that this will be developed nearer to the time of conversion. HSE will need to consider whether any such inspection and maintenance proposals are sufficient to ensure adequate integrity.

Polyethylene Pipes (PE)

PE pipework is currently used extensively in the LDS network to convey natural gas and has been used to replace and upgrade the gas supply infrastructure for a number of years, particularly since the 1970's.

The gas network industry has carried out a number of studies on repurposing the PE pipework and pipelines used within the network to hydrogen service. The evidence submission, Failure Modes and Permeation of old PE⁶⁵ extended studies into the use of polyethylene pipes for the distribution of hydrogen gas at pressures below 10 barg. This workstream reported on hydrogen testing with materials supplied, installed

64 Hydrogen Risk Mitigations – GDN risk mitigations selection proposal, Cadent, 2024

65 Vintage PE Pipes & Hydrogen, Radius Systems, 2024

and operated in the United Kingdom since 1969, referred to as historic or vintage materials. The findings from the study indicate that PE systems are not deleteriously affected by contact with hydrogen at gas distribution pressures.

Older PE has been subject to study in relation to permeation with The Failure Modes and Permeation of Old PE including quantification of permeation rates of PE, which had been aged through the application of heat. This study was conducted to consider potential risks associated with permeation within enclosed spaces and ducts. The evidence stated that there would not be a risk in terms of gas accumulating to recordable levels from permeation through the PE pipe wall. This is because the expectation is that the annulus would not be sealed to the PE pipe during mains insertion, volumes of permeation would be very low and there would be high ventilation rates of the carrier pipe from breaks in the pipe for service and tee connections. Further note should be taken that, in the event that gas supplies running through PE mains were at elevated temperatures, permeation rates would be higher but not likely to be significant. This assertion was accepted by HSE.

HSE raised questions relating to the scalability of the squeeze off trial. In wider application, damage could occur to the PE during operations under colder conditions, overzealous application of squeeze-off tooling and on thicker wall pipework, with older PE being potentially more susceptible to damage. The gas network industry response placed the emphasis upon correct application of operating procedures for the pipework parameters and conditions and is consistent with current operation of the natural gas system.

HSE was aware of failures of legacy PE which were reported within the US. This situation was reviewed by the gas network industry, and it was concluded that the specific type of PE used in the US was more susceptible to degradation than the vintage PE used in the UK system. The testing carried out within the Failure Modes and Permeation of Old PE supported this gas network industry conclusion.

The Failure Modes and Permeation of Old PE identified that there was no significant influence of hydrogen on the materials observed at the temperatures and pressures found in the gas distribution networks.

HSE considers that the evidence supports the view that PE is generally suitable for hydrogen conveyance within the local distribution network. However, older/vintage types of PE may be more susceptible to age related failures.

One area of concern related to greater permeation rates of hydrogen through the pipe wall that may accumulate, particularly within inserted mains and at elevated temperature. The gas network industry had emphasised that, although permeation of hydrogen is a lot higher than for natural gas, it was expected that the permeation would still be very low, with inserted main methodologies providing suitable escape points with no risk from accumulation.

HSE accepts the supposition that continued use of older/vintage PE does not pose an additional threat to pipe integrity, providing, as with current PE, correct pipework intervention operational procedures are adhered to.

Pipeline Interventions

Pipeline interventions that may be employed as necessary, including emergency interventions, were tested using hydrogen within the Microgrid test facility at Spadeadam, Live Gas Operations and Isolations within the H21 Phase 2A - Appraisal of Network Operations⁶⁶ submission. This submission provided further evidence pieces on commissioning and decommissioning pipeline sections, pressure and flow validation trials, pressure regulation maintenance, repair techniques and the finding and accessing of leaks.

The Live Gas Operations and Isolation Techniques⁶⁷ was stated as being successful in deploying the various techniques within hydrogen pipework systems. However, the efficacy of the sealing systems requires some improvement across all mechanisms. HSE has concerns with the range of leak rates experienced during the application of the isolation methods during the trials and perceived reliance on the bleed or vent between isolations. Additional work was carried out under laboratory conditions regarding leak rate and risk of ignition within Ignition Considerations, but this did not further evaluate isolation efficacy. The application of tooling inerting techniques procedures was proven effective in principle during the trials.

This would seem to be a similar experience to the application of other pipeline isolation tooling within the Transmission Network trials where application technique was proven but final sealing of the pipework was impacted by issues such as damaged seals due to residual swarf.

The Live Gas Operations Report⁶⁸ continued to test a number of further live operations. Metallic branch drilling was successfully performed, with the use of indirect purging being adopted. Further observations were made by the report as to improving the purging process on hydrogen specific equipment thus improving general efficiency.

The purge process was shown to be slow. HSE notes this may hamper timely intervention and increase the potential to miss out steps in the procedure or commence operations with an incomplete purge.

HSE identified two issues of concern within the Live Gas Operations and Isolations review:

66 H21 Phase 2A Testing – Part A – Planned live gas operations and isolation techniques, DNV, 2022

67 Live Gas Operations and Isolation Techniques, DNV, 2023

68 H21 Phase 2B Planned live gas operations, DNV, 2023

- The requirement to carry out an indirect purge on intervention equipment such as the Stopple tooling had been agreed, with indirect purging being required for drilling equipment referenced to Ignition Report EA_20_18⁶⁹.
- The other area of concern is in relation to the determination of seal efficacy using the look, see and feel criteria and the potential for accumulation of flammable compositions of gas with low leakage rates. Changes had been implemented following further study with a maximum of 0.2 mbar within the intermediate vent being specified. A positive pressure would still indicate the presence of hydrogen although within the vented section of the isolation and not in the work location.

HSE considers that further work is required to ensure isolation techniques can be deployed to ensure that adequate isolation of a piping system is accomplished in a reliable and repeatable manner. The various techniques will need to be suitably validated for the pipe material, line size and process conditions accordingly.

HSE's assessment of the Live Gas Operations Report highlighted concerns over potential inadequate purging being carried out due to inefficiency of the equipment. The issue of purge efficacy also extends to the potential loss of purge during drilling operations. HSE would expect that such an occurrence would be considered within the operational risk assessment and method statement and mitigated accordingly by suitable means.

Pipework repairs

HSE acknowledges that pipework repairs will be necessary at times e.g., to remediate degradation due to ageing etc. When applying a repair to a pipework section or pipeline HSE expects that such repairs would return the asset to a condition suitable for the design and operating conditions of the asset for a defined period in accordance with network operating procedures.

Trials described within the submission Technical Note Assessment of Repairs⁷⁰ saw six used pipe samples of steel, cast and spun iron that were prone to damage due to corrosion, brittle fracture or leakage through joints. Some samples exhibited existing leaks with others having manufactured leaks applied. A range of leak repair techniques were then applied, and the pipe sections subjected to a leak test for a 5-month duration.

The repair techniques applied were those historically applied across the gas supply network to repair pipework in a variety of situations. All repair techniques were able to be applied and confirmed as being leak free prior to the start of the trial.

69 H21 Phase 2: Ignition Considerations for Network Procedures, HSE, 2022

70 Technical Note 1521622 – Assessment of Repair Techniques, DNV Spadeadam Research and Development, 2022

The outcome of the trials saw the two-part injected repair to a joint showing consistent leakage for the duration of the test from the introduction of hydrogen, The heat shrink repair started to show signs of pressure loss after 3 ½ months in hydrogen service. The other repairs remained leak free for the duration of the test.

The report commented that the two failed repairs may have been due to issues with the repair application as opposed to incompatibility with hydrogen. HSE considers this credible, and as seen in industry, such repairs are sensitive to substrate preparation and ambient conditions at the time of application. Issues can also be experienced with the nature of suitable guidance and adherence to, suitable quality procedures. Even when correctly applied, some composite repairs have been known to fail prematurely in service with reference to the Energy Institute Guidance – Management of Engineered Composite Repairs – End User Good Practice Guidance and HSE Research Report – Composite Repairs, End User Good Practice.

The repairs that were applied and tested were considered by HSE to be of a temporary nature that did not see the pipework restored to its original specification or condition. HSE has potential concerns around the performance of such repairs under adverse or extreme operating conditions as well as those identified within the bad practice considerations, such as survival following internal pipework ignition.

HSE would expect such repairs to be subject to a suitable management system to identify age, type, and location and to address monitoring over time. HSE has noted that there had been little by way of demonstration as to how such repairs were recorded and effectively monitored.

The Technical Note Assessment of Repairs underlines the difficulty in applying such repairs in operational conditions such that suitable conditions are maintained, and adequate quality control applied. The trial conditions would suggest the repairs were applied in relatively ideal conditions as opposed to field conditions and hence may be expected to perform better.

HSE considers this trial to be informative but not conclusive and further work would need to be undertaken to validate the range of such repairs in hydrogen service considering the various materials, failure types, design life and operating conditions. The consequence of failure of a repair should also be considered.

Materials used within such repairs is a developing area of research in relation to compatibility in hydrogen service and long-term effects.

Leak Detection

The approach to leak detection for buried assets in hydrogen service was captured within evidence submission report - *Finding and Accessing Leaks H21 2a*⁷¹ and *2b*⁷².

The procedures followed were in accordance with DNV Spadeadam Research and Development: Accessing of Pre-formed Leaks method statements. Research was undertaken on pre-established backfilled leak locations with stabilised gas concentration levels. A range of manufactured leak features were present within the pipework at known locations.

The general findings from the trial identified that each of the engineered leaks gave rise to flow rates of between 2 to 3 times higher for hydrogen compared to natural gas for leaks into the ground for similar operating pressures. Whilst higher concentrations were observed in sample holes for hydrogen, the readings decayed with distance from the leak in a similar trend for both hydrogen and natural gas. In most cases, normalising the sample hole measurements for the flow rate of gas meant that the decaying trends for the two gases became closer. The report concluded that this could be interpreted as an indication that the in-ground behaviour has little dependence on the gas properties (namely density and viscosity).

The report was not able to conclude from the evidence provided that the techniques applied could be used to safely excavate directly onto a leak site if the criteria are continually met up to the point of exposing the leak site. Note was also made within the report that there was not enough evidence in this work piece to recommend this is undertaken on real leaks.

HSE notes that, for the study, the leak location was known and the location isolated prior to further work. It was not clear how locating gas escapes on the network could be conducted in practice (beyond trials). In the event of repurposing, identification and isolation of escapes would not always be practicable.

The gas network industry asserted that, whilst the leakage location for this test was known, the same methods of locating a gas escape were deployed. This was a first look at utilising existing equipment such as the percussion bar and rock drill in a remote-controlled environment. Further realistic escape locating activities were demonstrated through Phase 2B of the project utilising existing highways and infrastructure layout. It was not the intention of the gas network industry to decommission or isolate the leaking main, as the escaping gas is used to pinpoint the location of failure. In the event the main was isolated, the report proposed that replacement instead of repair would be more practicable.

71 H21 Phase 2A – Finding and Accessing Leaks, DNV, 2022

72 H21 Phase 2B – Finding and Accessing Leaks, DNV, 2023

HSE considers that the evidence has not fully demonstrated how leak detection and repair would be addressed in practice with the reporting also noting additional work that would be required to support the safe excavation down to the leak site.

At present this represents an evidence gap, however, with further development of safe working practices, it is feasible that this can be addressed.

Decommissioning methodology

The likely pathways to any adoption and rollout of hydrogen for heating remains to be defined, however it is likely that there will be a requirement to decommission sections of the gas supply infrastructure.

There are a number of safety issues to be considered as relate to decommissioning procedures and the status of assets left in situ and out of use. Capped live pipework, in particular services, would become prone to on-going corrosion, if steel, and or 3rd party damage or interference due to unexpected location of assets, particularly if properties use an alternative energy source. Out of use but live mains pose a risk due to aging or damage by 3rd parties. Decommissioned mains and pipework could form conduits to inadvertently transport gas leaking from other sources such as other damage or leak sites.

The DESNZ Decommissioning Methodology Note⁷³ details how decommissioning of sections of the network could be undertaken for PE, larger and smaller metallic mains together with service pipe decommissioning. Various levels of decommissioning and procedures were considered ranging from removal through to cap and abandon, cap fill and abandon and mothball. A decommissioning decision tree was presented to help inform the level of decommissioning that would be appropriate for a given asset.

DESNZ advised that this work is centred around hypothetical modelling to provide basic assumptions around processes.

HSE's review of the submission highlighted the following issues for consideration:

- The potential length of time that an uncapped but isolated service may remain live, or a capped live service remain in place prior to removal.
- Concern relating to the lack of consideration for purging and venting of redundant assets.
- The use of inert gas to mothball sections of pipelines as there had been no consideration for how the gas content was to be monitored and maintained.

⁷³ Heat Infrastructure Transformation Network and Storage Modelling - Decommissioning Methodology Note, DESNZ, 2024

- Management of large Medium Pressure (MP) assets beneath railway or major road crossing etc.

There are current regulatory duties on how decommissioned services should be dealt with. This includes timescales for disconnection close to the main which remains the most relevant consideration in order to reduce risks associated with potential loss of containment of a live, unused service.

It is clear that further consideration is needed of how decommissioning at scale would be undertaken and managed for a range of pathway scenarios. Decommissioning represents a distinct issue from the evidence base provided for repurposing.

Conclusions

HSE considers that it is potentially feasible to convert the LDS from the transportation of natural gas to hydrogen.

However, while the evidence demonstration supports near term potential use of the LDS, the longer-term impacts from hydrogen service remain to be determined.

The level of assurance that can be gained from experimental data when considering potential long-term real-world exposure is limited. Operational learning, supported by further research, will be key to validating the evidence base provided.

While elements of the LDS will be subject to an inspection and maintenance regime, the buried and legacy pipework in the LDS presents a challenge to inspection. Reference has been made to enhanced leakage surveillance, but specific solutions have not been presented for HSE's consideration.

There are a range of outstanding issues that would need to be addressed prior to any wider deployment of 100% hydrogen, including:

- There is reduced confidence in the data on asset type and location in the LDS, as compared to the LTS. However, there remains the need to ensure individual pipelines are adequately assessed in relation to matters such as material properties, historic operating and process conditions, initial build quality assurance and condition to determine suitability for operating with 100% hydrogen. Acceptable operating parameters need to be confirmed and verified.
- HSE considers that it is feasible that legacy iron pipes of suitable specification and condition can be operated in hydrogen service up to 2 barg, based upon the original design pressure of the pipework. This would need to take account of degradation of the pipework properties due to hydrogen, and that iron pipes in hydrogen service need to be subject to a time bound, risk based

decommissioning programme. However, there are a range of further considerations that would need to be considered, including:

- The development of suitable inspection and maintenance regimes for iron pipes, currently referred to as condition assessment. This would not be expected to be a one-off assessment but the basis of a suitable approach to integrity management of iron assets. There has been insufficient evidence provided so far relating to what inspection and surveillance techniques will be deployed, and maintenance regime implemented, over and above the current approach to enable HSE to comment on its suitability. The gas network industry suggested that this will be developed nearer to the time of conversion. HSE would need to consider whether any future inspections and maintenance proposals are sufficient to ensure adequate integrity.
- As the use of existing in-service iron pipes, and in particular pit and spun, are not considered as being in accordance with Relevant Good Practice, and due to the age and condition of such assets, it is expected that an on-going replacement program will be maintained.
- There will be a requirement that additional iron mains will need to be replaced, beyond those that are already planned to be completed by the end of 2032 within the scope of the Iron Mains Risk Reduction Program, to meet an acceptable risk threshold, as defined within the GDN Hydrogen Risks Mitigation submission. This is accepted by the gas network industry in their evidence submissions.
- Full account of the conclusions of the IGEM peer review, or other independent/standards setting body reviews should be taken and applied to the continued use of legacy Iron Mains in hydrogen service.

The work covering cast iron ancillary assets was limited to operating at 7 barg or below. The use of cast iron with hydrogen above this pressure has not been evidenced. Based on current industry standards, valves and other fittings and equipment items containing cast iron, pressure retaining or other critical parts in contact with hydrogen would not be suitable for continued operation above 7 barg.

HSE considers that the evidence generally supports the use of iron within ancillary equipment items such as valves and regulator bodies operating at 7 barg or below. This is based upon the specific material quality, maximum operating pressure capped at 7 barg and the general thicker wall thickness and applied geometries providing an increased design margin. There may be limitations on the use of some assets based upon the criticality and degree of hydrogen facing elements within such assemblies that should be subject to specific operational review.

HSE notes that research into materials and components is a developing area in relation to the hydrogen economy, including in relation to long term testing of cast

iron. There are, however, a number of publications and international projects that have presented data on the performance of cast iron in gaseous hydrogen over the last five years, and this is an area where further work is expected to become available in the coming years. This should bring clarity on the performance of cast iron in hydrogen, over time.

In relation to PE pipework, HSE accepts the demonstration that continued use of vintage PE was not considered to pose additional threat to pipe integrity providing, as with current PE, correct pipework intervention operational procedures are adhered to.

HSE considers trials on pipework repairs as informative but not conclusive and further work would need to be undertaken to validate the range of such repairs in hydrogen service considering the various materials, failure types, design life and operating conditions. The consequence of failure of a repair should also be considered in the case of hydrogen. Materials used within such repairs are still under scrutiny in relation to compatibility in hydrogen service and long-term effects.

HSE considers that the evidence has not fully demonstrated how leak detection and repair would be addressed in practice with the reporting also noting additional work that would be required to support the safe excavation down to the leak site. At present this represents an evidence gap. However, with further development of safe working practices, it is feasible that this can be addressed.

It is clear further detail needs to be considered into how decommissioning at scale would be undertaken and managed for a range of pathway scenarios. There are current expectations on how decommissioned services should be dealt. This includes timescales for disconnection close to the main which remains the most appropriate position in order to reduce risks associated with potential loss of containment of a live unused service.

The NHSA has recognised the potential for increase in velocities to accelerate degradation, e.g. via vibration, erosion, etc. Written Schemes of Examination should be reviewed and updated as required.

As with the LTS, for live gas operations HSE considers that further work is required to ensure isolation techniques can be deployed so that adequate isolation of a piping system is accomplished in a reliable and repeatable manner and the various techniques suitably validated for the pipe material, line size and process conditions accordingly.

As with the LTS, HSE's assessment of the Hydrogen Ready Components studies concluded that the approach provided a robust means of assessing and ranking

components and materials for suitability with hydrogen within the limits and scope of the study. The following gaps and concerns, however, remain to be addressed:

- The range of sealants addressed in the Hydrogen Ready Components submission was of particular concern as this impacts a number of assemblies and piping systems also considering degradation over time. Other studies on sealants (Sealant Suitability and Materials and Fittings) had provided more detail but there remained evidence gaps in relation to suitability and use.
- Further testing of sealants for use in hydrogen service would need to be undertaken to build upon the existing studies, especially in relation to screwed fittings as varying results had been reported from the trials. The findings would need to be developed to provide suitable guidance on the use of suitable products and application, including any restrictions. The Hydrogen Ready Components submission refers to a test program known to be underway on sealants.
- The justification for use of spring steels within a hydrogen environment was considered to be dependent on the service conditions of a particular asset. Therefore, each asset type will need to be further assessed prior to conversion.
- Some used assets or asset types had not performed well during initial integrity testing and following hydrogen leak testing. Although potentially not specifically related to material compatibility, this raises questions over the level of maintenance and inspection required for such assets for use within a hydrogen environment.

As with the LTS, the gas network industry recognises the need to develop a management process that includes the condition assessment of above ground network assets. The development of IGEM standard TD/22 supports this approach for ensuring such assets are maintained in an acceptable condition, being leak tight and compatible for operation in hydrogen service at the defined process conditions. However, HSE notes that the scope of this standard was limited to trials. Therefore, this standard may need to be developed to support any wider rollout.

Section 10. Downstream

The following sections consider the gas supply and assets downstream of the Emergency Control Value (ECV). The ECV is a safety mechanism at the end of the gas service pipe, prior to the connection of a gas meter to the gas mains. The ECV is situated where the gas network or gas distribution pipe meets the gas meter. The ECV outlet is considered as the end of the distribution network.

The downstream evidence assessment considers a range of end use settings. The following sections cover domestic, multi occupancy buildings (MOBs), and commercial and industrial use.

Section 10.1 Domestic

It is potentially feasible to convert the domestic natural gas system for use with 100% for hydrogen heating. However, a full evidence demonstration has not been made at this time.

In particular, it is recognised that the phenomenon of air ingress is a developing and evolving area of research. Evidence submissions on air ingress indicate that this issue has the potential to be successfully resolved. However, if effective mitigations cannot be established, this issue represents a barrier to the feasibility of the roll out of hydrogen into domestic settings at a national scale. This represents a significant evidence gap.

The mitigations proposed appear appropriate, however HSE would expect to see the potential for smart detection with integrated Automatic Isolation Valves to be explored further as technology evolves.

Introduction to Domestic

This section considers the gas supply and assets downstream of the ECV in domestic settings excluding multi occupancy building (MOBs).

HSE reviewed evidence that sought to demonstrate that domestic systems can be repurposed for use with 100% hydrogen for heating. The gas network industry's evidence in support of repurposing the domestic pipework systems from natural gas to 100% hydrogen was largely provided within the hydrogen domestic pipework conversion strategy, air ingress research and ignition consequence research. This was supported by various studies related to material suitability and compatibility.

HSE's evidence assessment

Domestic Pipework Integrity

The integrity and suitability of the materials in downstream gas supply systems needs to be understood to determine what risks and mitigations need to be considered in the event of a leak. The gas distribution industry has assessed the materials downstream of the ECV as consisting predominantly of copper, brass, carbon steel and some aluminium. This has been described within DNV document Technical Memo – End User Safety Evidence (EUSE) Hydrogen Purity –

Contaminants Impact⁷⁴ and EUSE Hydrogen Domestic Pipework Conversion - Final Report⁷⁵, as verified by pre-hydrogen heating trial inspections. Further, the Hydrogen Conversion Strategy Pipework Literature Review and Interim Report⁷⁶ carried out a review of the materials used in domestic gas pipework installations and found that most materials identified would be satisfactory for use with hydrogen. HSE notes that the installation of lead has not been permitted for many years but there is no requirement to remove it unless it is damaged or leaking. This means that it is likely that there is legacy lead pipework that would also need to be addressed.

It is considered by the gas distribution industry that leaks within an uninterrupted length of pipework are credible but considered very rare, with most leaks occurring at joints and fittings. The evidence submissions Hydrogen Conversion Strategy Pipework Literature Review and Interim Report and EUSE Hydrogen Domestic Pipework Conversion - Final Report found that most materials identified within domestic premises would be satisfactory for use with hydrogen, citing copper, steel and stainless steel specifically as being suitable. Work had been carried out by *The Welding Institute*, Provision of End User Skills and standards for heat supporting research and evidence – metallic testing⁷⁷ on the impact of hydrogen on malleable iron and lead. Some differences were noted in the failure characteristics of the malleable iron with limited impact on lead. Lead, however, is defined as being unsuitable by the gas industry due to its low melting point, inherent weakness and means of jointing. The BSI Standard PAS4442 sponsored by The Department for Energy Security and Net Zero defines the material requirement for pipework and fittings for use within hydrogen gas installations (downstream of the ECV).

It would be expected by HSE, and has been indicated by the gas distribution industry, that all properties would undergo a pre-conversion inspection of gas supply pipework and fittings to ascertain condition and suitability as far as was reasonable. In the event of non-conforming materials, such as lead and other composite materials, or materials in poor condition being identified, the gas distribution industry have undertaken that they would be removed, and any repair executed during pre-conversion inspection and preparation activities.

Gas distribution industry surveys found that fittings used within domestic gas pipework installations comprised mainly of soldered and brazed end feed copper, brass compression and screwed types of various materials with growing use of crimp (press) fit type pipe fittings. The materials from which most fittings had been manufactured were considered as being suitable for hydrogen service although the

74 Technical memo – EUSE Hydrogen Purity – Contaminants Impact – Materials in Domestic Installations, DNV, 2023

75 EUSE Hydrogen Domestic Pipework Conversion – Final Report, Kiwa Energy, 2023

76 Hydrogen Conversion Strategy-Pipework – Literature Review and Interim Report, Kiwa Energy, 2023

77 Provision of Hydrogen End User Skills and Standards for Heat Supporting Research and Evidence – Metallic testing, TWI, 2023

use of leaded brass is currently subject to further research. Pipework and soldered fittings were subject to testing, as reported in *Research into Suitability of Solder and Brazing Alloys for Use in Low Pressure Hydrogen Gas Installations*⁷⁸. The research concluded that the experimental work and statistical analysis provided evidence in support of the use of solder and brazing alloys in low pressure hydrogen gas installations.

A range of pipework sealants for threaded joints had been tested with variable results that may provide some challenge with some screwed pipework and fittings, including screwed joints of larger bore pipework within MOB's and other complex settings, such as public buildings, and large commercial premises. The evidence submission *Sealant Suitability – Final Report*⁷⁹ identified that over half of the non-hardening compounds suffered failure of at least one joint when assembled without support. Support referred to an additional component added to the joint to form a solid blockage, or matrix, to bridge larger gaps in the joint. The use of support with non-hardening compounds appears to significantly improve the reliability. HSE considers that, without further investigation, it remains unclear whether the cause of failures with non-hardening sealant was hydrogen incompatibility or sealant performance in general. HSE considers this represents an evidence gap.

Two of the most common methods of joining copper pipe and fittings are soldering and brazing. The suitability of solder and brazing alloys for use with hydrogen was assessed through the *Solder and Braze evidence submission*. Samples were made up using copper pipework and either couplings or swaged pipework, being brazed or soldered and subject to tensile testing. The ultimate tensile stress and strain to failure of the samples were used as the basis for the analysis.

In the reports, soldered joints were tested using four different combinations of flux and solder. Brazed joints were fabricated using a copper phosphorous braze filler.

The tensile tests were conducted under different hydrogen environments of 1 bar gaseous hydrogen, and hydrogen charging (where specimens were chemically pre-charged with hydrogen as well as filled with 1 bar gaseous hydrogen). Testing was conducted at ambient temperature and at an elevated temperature of 50°C, with the results being compared to baseline tensile test results conducted in air.

The flux and solder combination used to make the joint, in either the coupler or swaged joint geometry, was presented as having no significant impact on the joint integrity. The loading behaviour of the sample under tension was found to be dominated by the base copper piping. Testing in gaseous hydrogen, achieved through filling the samples with 1 bar hydrogen, had no clear impact on joint integrity,

⁷⁸ *Research into Suitability of Solder and Brazing Alloys for Use in Low Pressure Hydrogen Gas Installations*, Frazer-Nash Consultancy Ltd., 2024

⁷⁹ *Hydrogen Skills and Standards for Heat: Sealant Suitability*, Steer Energy, 2024

although absorbed hydrogen, achieved through hydrogen charging, did appear to have a slight effect on specimen integrity. A small reduction in ultimate tensile stress was observed over most hydrogen charged samples compared to the baseline samples. The soldered charged samples demonstrated a decrease in mean strain at failure with increased variability that was not observed for the pipe or brazed samples.

HSE noted that the preparation of the samples by hydrogen charging was more extreme than the samples would experience in normal service, providing a degree of conservatism to the findings.

The evidence concluded that the experimental work and statistical analysis provided evidence to support the use of solder and brazing alloys in low pressure hydrogen gas installations. Other factors, such as joint quality and temperature, were observed to have a more significant impact on joint integrity.

Overall, HSE considers that evidence on the compatibility of typical materials used downstream of the ECV within domestic and small commercial premises shows that most conventional materials are acceptable for use in hydrogen service. It is noted that the evidence has given consideration to the relatively low operating pressure compared to the theoretical maximum operating pressure of a typical gas carcass.

When considering domestic gas systems, a series of relevant Publicly Available Specifications (PAS) standards has been developed by BSI Standards that define best practices for a product, service, or process. Of particular relevance to hydrogen are BSI PAS 4442-2024 that covers material requirements for pipework and fittings used in hydrogen gas installations and BSI PAS 4443-2024 defining assessment criteria for ancillary valves, devices and components used in hydrogen gas installations. PAS 4442 and PAS 4443 provide guidance on material suitability for pipework and fittings within this context.

HSE notes that the survey evidence demonstrates that there will be some non-conforming or unsuitable materials in some properties that would need to be replaced prior to any conversion.

HSE also notes that materials used to assemble screwed joints will be difficult to evaluate in some instances without disassembly. Disassembly of threaded rigid pipework is a significant task which, in many cases, will involve the full removal of the pipework and refitting. Additionally, HSE has concerns that the evidence demonstrates that some thread sealing solutions show low reliability, particularly over time. This could have implications for pipework integrity over extended periods but, as yet, these have not been quantified.

Domestic pipework conversion

Prior to any conversion typical domestic pipework systems, (termed carcasses) or pipework installations would need to be verified as comprising of compatible and suitable materials. The quality and condition of pipework installation would need to be verified. Difficulty in gaining adequate access to some installations where pipework is concealed will make it difficult to determine the materials of some pipework runs and confirm suitable quality of installation and adequate integrity. Confirming the suitability and integrity of pipework within domestic and light commercial premises remains of critical importance to the repurposing of the natural gas network for 100% hydrogen use.

Studies presented to demonstrate the efficacy of pipework conversion included Hydrogen Conversion Strategy-Pipework – Literature Review and Interim Report Feb 2023 EUSE Hydrogen Domestic Pipework Conversion - Final Report Oct 2023.

The Hydrogen Conversion Strategy-Pipework – Literature Review and Interim Report Feb 2023 considered the risks associated with conversion (repurposing) of natural gas domestic pipework installations to 100% hydrogen installations within the current UK gas network.

The scope of this project focused on domestic gas installations downstream of the ECV to the appliance inlet. The report analysed accident and leak data to explore the types of leaks that have occurred in natural gas domestic pipework, taking account of the different behaviour of hydrogen and methane leaks.-The research considered types and sizes of leaks under four classifications, although there were some differing definitions within the reporting. The four classifications were as follows:

- Very Small leaks (laminar flow) – with hole diameter equivalent of 0.6 mm
- Small leaks (laminar flow) – with hole diameter equivalent of 1.8 mm
- Medium / Mid-sized leaks also referred to as - Large leaks (turbulent flow), mainly interference such as drilling screwing or nailing through pipework
- Full Rupture / - Large (turbulent flow) leaks from failures such as joint failure, being generally spontaneous in nature.

The report found that generally, for a small leak the hydrogen leak rate would be 120% of that of natural gas (assuming laminar flow). For a large leak the hydrogen leak rate would be 280% of the natural gas rate (assuming turbulent flow), based upon volumetric flow as opposed to mass flow.

The report determined that very small and small leaks can occur spontaneously with 98% of reported leaks being due to poorly made joints, compression fittings, valves stems and spindles. Such smaller leaks were thought by the gas supply industry not to result in a buildup of gas above the lower hydrogen flammable limit “at room scale” but this would be determined by factors such as room geometry and

ventilation. Medium or midsized leaks, also referred to as larger leaks, such as those due to interference i.e. from drilling or insertion of screws or nails, accounted for 98% of the remaining 2% of leaks, i.e. 1.96% of reported leaks. Other large leaks, such as rupture or total joint failures, would give much higher leak rates and hence more substantial build-up of hydrogen but were established as being rare events i.e. 0.04%.

HSE considers that the types of leaks identified within the studies are credible and it is recognised that most of the medium sized leaks are most likely due to interference damage such as due to DIY or home renovation activities.

The report also reviewed the materials and methods of pipework installation and credible failure modes. It also considered a number of existing and emerging pipework inspection techniques.

The report Hydrogen Domestic Pipework Conversion - Final Report Oct 2023 sought to provide additional detail and rigour to the suitability of carcasses for conversion to hydrogen gas. The report commented on additional research on fittings and pipework assemblies as well as on probabilities of critical failures, likely consequences, and the efficacy of available inspection techniques. Of particular note was the recognition of the limitations of visual inspection. The report acknowledges that some pipework will be hidden, and no current technology exists to effectively identify the materials, or the methodology of installation, support or condition in situ. Therefore, visual inspection combined with pressure testing and appropriate risk assessment is the report's recommended approach. This is also the approach outlined in the IGEM H1 and H2 standards.

HSE considers that most materials identified within properties during the pre-village trial inspections, carried out at both the Whitby and Redcar sites were compatible for hydrogen service with some exceptions where some identified materials were deemed unsuitable (note, both the proposed Redcar and Whitby Hydrogen village trials did not progress to live trial stage). The gas distribution industry has confirmed that non-confirming pipework materials would be replaced prior to any future conversion. There is a question about how to determine if hidden pipework is a non-confirming material. Intrusive inspection techniques (following risk assessment) are likely to be required to support the commitment to replace non-confirming pipework.

HSE considers there to be limitations in the efficacy of the visual inspection technique (e.g. identifying joints that have been fluxed but not soldered or properly tightened) and in some instances it is not able to be easily deployed such as in wall voids and under floors. HSE considers that additional means of confirming adequate integrity will be required. This represents an evidence gap at this stage.

Any risk assessment should take adequate account of the inspection efficacy in identifying all credible degradation mechanisms, materials and quality of installation issues that may compromise pipework integrity.

It has been identified within the evidence that there are some fault conditions and installation quality issues that may not manifest under normal operating pressure or at the current 82.5mbar pressure test, an example being a soldered joint that had been fluxed but not soldered. Such joints are hard to identify visually, may pass a pressure leak test due to flux applied to the joint but could lead to joint failure at a later date as the flux dries out or as the unsoldered joint moves. The evidence determined that the pipework would, however, have to move more than the amount of fitting engagement for a full-bore leak to occur, but failure due to cracking of dried flux could occur with limited movement but lead to far lower leakage.

The report Hydrogen Domestic Pipework Conversion - Final Report Oct 2023 advises that, in certain circumstances, a pressure test of 1barg would be required to break an unsoldered joint with dried flux and initiate a leak that could be detected. This would also disrupt other poor joint types to enable detection. However, concerns were raised over the potential to induce further weakness or leakage as a result of the elevated pressure test with a standard test of 82.5 mbarg being preferred by the gas distribution industry.

HSE considers that applying a pressure test of 82.5 mbarg pressure test compared to a 1barg test would reduce the level of detection of some critical pipework faults. HSE noted that the 1barg test was to be performed whilst meter and appliances had been removed and following the fitting of appliance isolation valves with purge points that were suitable for the pressure. If the elevated pressure test at 1barg is not to be adopted then other suitable methods would be required to confirm adequate integrity, to ensure all credible fault conditions were captured to an acceptable level and probability of detection.

The evidence concludes that conventional materials such as copper, steel and methods of jointing are suitable for hydrogen conversion based on the relatively low operating pressure versus the theoretical maximum operating pressure of a typical gas carcass and material caveats as defined. However, HSE considers these conclusions to be limited by the need to define suitable inspection scope and risk assessment by individual property in order to provide adequate assurance of gas carcass integrity on a property-by-property basis.

Air ingress

The operation of hydrogen in a demonstration network facility in Redcar, indicated that when the gas supply system had been isolated for a prolonged period of time, hydrogen gas could escape allowing air to ingress into the pipework system. This led to the generation of a flammable atmosphere within the pipework that was able to be

ignited due to burn back when an attempt was made to ignite an appliance. This phenomenon was researched and reported via Enertek Oxygen Ingress Report⁸⁰, Steer Energy 380 Air ingress in Domestic Gas isolated Installations Report⁸¹, and Cadent Air/Oxygen Ingress in Domestic Gas Installations Phase 1 Summary Paper⁸².

Both studies looked at the mechanism by which air could enter the pipework system as well as the mechanism by which the flammable mix within the pipework may be ignited. The ingress of air was able to be repeated under test conditions when the supply had been isolated within what was considered as a gas tight piping system.

It was reported that a typical gas system, when isolated, would not have sufficient integrity to maintain pressure to prevent a degree of gaseous transfer over a prolonged period of time. The studies reported anecdotal knowledge that the phenomena occurred with natural gas that manifested in what was described as 'rough starts' of boilers. The phenomena with natural gas was proven by experiment and was of a demonstrably lower consequence when ignited compared to hydrogen.

The scope boundary of the air ingress studies is limited to downstream domestic installations. The gas distribution industry indicated, however, that the foundations of understanding can be applied to other end-use settings. Recommendations for next steps to be investigated and researched are outlined within the reports. Whilst not the subject of this section, HSE considers air ingress to have additional ramifications for hydrogen use within MOB's and how industrial conversion would need to be conceived and designed to avoid such scenarios on larger systems.

The studies demonstrated that it would be difficult, and probably impractical, to ensure legacy piping systems had adequate integrity such that hydrogen would not escape from an isolated pipework system due to very low-level seeps, weeps and diffusion.

The evidence reports presented hypothetical mitigations which could be implemented to take account of this phenomena. Examples included:

- Tamper proof/lockable ECVs – these are latching ECVs requiring unlocking by an (unspecified) competent person who would ensure suitable post isolation purging of the system. These systems would likely have operational ramifications.

80 Oxygen Ingress Interim report 2, Enertek International Ltd., 2024

81 380 Air Ingress in Domestic Gas Installations Final Report, Steer Energy, 2024

82 Air/Oxygen Ingress in Domestic Gas Installations Phase 1 Summary Paper, Cadent, 2024

- Deployment of appliances designed and manufactured to be tolerant to air ingress on startup and designed such that burn back could not occur. Such designs would need to be adequately tested and validated.
- Ensuring that downstream pressure is maintained in the event that pre-payment meters automatically isolate the system in 'zero credit' mode through either:
 - The presence of a mechanical let-by (minute, physical hole inside the closure valve – akin to what already exists in mechanical EFVs).
 - 'smart' software solution – which enables closed pre-payment meters to periodically re-open, to re-pressurise the downstream pipework.

The evidence suggested that some of the possible mitigation measures / methods may be suitable / pragmatic in the short or mid-term (e.g., for use in future trials due to scale of the projects and level of technical support), but may not be feasible in the long-term, wider scale roll out. The work to date has not resulted in physical mitigations.

The Steer Energy Air ingress in isolated installations report confirms that this is a live, developing area of research for the gas distribution industry. HSE considers that the report also indicates that considerable further work is required in this area.

HSE considers that the research carried out following the Redcar incident on behalf of the gas distribution industry was of good quality and informative. HSE notes that the scope boundary of the air ingress studies is limited to downstream domestic installations only. Further, HSE considers that the approach outlined to domestic air ingress mitigations at scale remains to be confirmed by the gas distribution industry and equipment suppliers. Whilst suitable resolution may not be technically insurmountable, a current lack of a suitable resolution represents a significant evidence gap.

Ignition Probability and Mitigation Considerations

The report Ignition Probability in Buildings with Small Services⁸³ considered the risk of ignition in the case of gas leaking and accumulating within a building or enclosed space. The report presented four basic-stages of an incident, as being:

- Leak event
- Subsequent release of gas
- Ignition and
- Consequence analysis of the ignition

⁸³ Ignition Probability in Buildings Associated with Small Services, Steer Energy; Astrimar, 2023

Immediate ignition of a significant leak causing a flame was not necessarily considered the most hazardous outcome, although from larger turbulent leaks with hydrogen flowing at almost three times the volumetric rate of natural gas, the resulting flames were similar in size and hence consequence.

The more hazardous outcome related to the accumulation of gas and potential risk of explosion. Hydrogen plumes from leaks in free space reached non-ignitable concentrations within one metre from the leak source with ignitable plumes of hydrogen reaching up to twice the distance of methane for the given leak scenario. Of specific concern were leaks of gas into small, poorly ventilated spaces, such as a meter cupboard, which could quickly build into an explosive mixture. However, within the scope of this study, detonation (rather than deflagration) was deemed very unlikely to occur as there is no directional constraint (such as a pipe) to encourage acceleration of the flame front in a single direction, and the plume cloud would be unlikely to be large enough for a deflagration explosion to transition to a more destructive detonation.

Additional work has been undertaken since this report was written, specifically looking at consequences from ignition, in the Ignition Consequences Report⁸⁴. It was concluded from this later work that detonation is possible in small, confined spaces, specifically, in the experiments undertaken, in kitchen cupboards. The levels of confinement in the experiments are analogous to those in a meter cupboard, implying that detonation is a possibility in the case of a leak. Further information on the Ignition Consequences Report can be found in the Risk Assessment section of this document. The report concluded that Excess Flow Valves (EFVs) can effectively mitigate against larger leaks.

The experiments included drilling into a live gas pipe, that did not ignite methane or hydrogen. Additionally, the trials involved cutting into a steel pipe with an angle grinder that did not initially ignite the methane or hydrogen, but which did cause ignition on reapplication of the grinder. This evidence was presented as suggesting accidental damage to a buried pipe whilst working will not necessarily result in ignitions. However, subsequent ignitions on reapplication of the ignition source (grinder) may result in larger, more energetic events given the additional gas leakage.

The study looked in some detail at leak site (perforation) geometries in relation to leak flowrate from varying damage mechanisms although it may be difficult to predict likely breach geometry for a given scenario as it may be dependent on many factors.

The installation of an EFV at the ECV outlet, matched to the maximum gas meter capacity flow rate, has the potential to prevent the largest gas leaks such as those

84 NIA 344: Ignition Consequences Final Report, DNV, 2024

commensurate with an open-ended pipe. These types of leaks are generally associated with the most severe natural gas explosions. It must however be recognised that substantial leaks, capable of causing severe damage if ignited, may still be possible if they are below the maximum gas meter capacity. Any benefit from the fitting of an EFV could be maximised if its set point (activation point) was aligned closely to the actual maximum gas load from appliances within the house. HSE notes that this could cause additional installation time for the EFV and when appliances are changed in the future.

The report compared the base case results between natural gas and hydrogen that showed a reported similar relative increase in ignition probability for hydrogen over natural gas of approximately 1.6 times.

The automatic isolation of the gas supply in the event of a leak would provide further mitigation against ignition, providing suitable detection could be installed and the efficacy of the detection system for hydrogen gas is proven with such systems to be a major mitigation measure in terms of providing an alarm. A project was implemented that looked at this principle and carried out further study into the types and reasons for releases to occur. The report Use of Automatic Isolation Valve (AIV) Systems with Hydrogen Final Report⁸⁵, considered alternative means of automatic isolation. The study focussed upon medium scale-commercial, users of hydrogen, however, the findings were presented as being transferable to domestic and other end users.

High level conclusions from the experiments provided evidence that:

- hydrogen was more detectable than methane;
- hydrogen dispersion was more uniform than methane; and
- hydrogen leakage is likely to be detected more quickly than methane for each leakage scenario.

AIVs that use gas detectors were presented as being a good risk mitigation method to respond to leakage in gas installations using hydrogen. This implies that the use of gas detection to provide a warning through local visual and audible alarm would also provide an effective level of mitigation, even if not configured to close an AIV. The Hydrogen Risk Mitigations GDN Risk Mitigations Selection Proposal rev 1.0 report⁸⁶ did, however, consider AIV's as an inappropriate risk mitigation solution for domestic installations due to predicted technology readiness level (TRL) in 2032 (with regards to connectivity technology and reliability of said technology being unknown for a large population such as domestic houses) with the report favouring the use of detectors and ventilation. The report noted that future projects such as HyBreak are investigating AIVs in domestic settings and acknowledges that whilst the technology was already commonly found in non-domestic natural gas installations, if proven to be possible in a domestic environment, it will transform the

85 Use of Automatic Isolation Valve (AIV) Systems with Hydrogen Final Report, Steer Energy, 2023

86 Hydrogen Risk Mitigations – GDN risk mitigations selection proposal, Cadent, 2024

approach to domestic gas safety in the UK reducing the reliance on more disruptive ventilation. HSE's consideration of this is discussed further below.

Ignition Probability in Buildings with Small Services research raised a number of further concerns or queries, several of which had been further researched within separate studies such as static ignition risks. The level of gas accumulation within meter boxes was of concern given the readings obtained and how these may generally impact understanding of buildup within other spaces. The test work in this instance was carried out at the end of the study with no resource to repeat the trial to thus validate the result. A degree of experimental error was present but not specifically identified. Releases into confined spaces and delayed ignition was identified as giving concern and the potential perception from the trials that a hydrogen leak from cutting into a live hydrogen pipe would not initiate an ignition, whereas it would likely pose a considerable risk of ignition. HSE notes that emphasis was placed upon immediate ignition probability and that work in this area should also consider the sources of ignition.

HSE considers the findings from Use of Automatic Isolation Valve (AIV) Systems with Hydrogen Final Report provide further support for the development and use of gas detectors for use with hydrogen installations. The criteria and configuration of such devices remains to be confirmed i.e. such as local alarm only, configured to provide a remote alarm to a call centre and local alarm, or to also close a local automated isolation valve or interact with a smart meter. Development of such technology may better define considerations of cost efficacy and practicality of the fitting of such devices prior to any conversion commencing at scale.

NO_x

NO_x refers to both nitrogen monoxide (NO) and nitrogen dioxide (NO₂). HSE understands that the gas network industry is undertaking research in relation to NO_x emissions associated with hydrogen heating, however this is not within scope of this evidence assessment. Currently, NO_x is not a parameter that is generally considered in domestic downstream gas even though NO_x is an emission from the combustion of natural gas. Given the adverse health effects of NO_x, it is important to establish whether the combustion of hydrogen in appliances will cause an increase in NO_x emissions.

Workplace Exposure Limits (WELs) are the British occupational exposure limits which include limits for NO and NO₂. These limits are applicable to workplaces and therefore not related to domestic gas appliance uses. The Ecodesign of Energy-related Products Directive (ErP), underpinned by the Ecodesign for Energy-Related Products Regulations 2010 in the UK, enforces maximum NO_x emissions for appliances using gaseous fuel. The Office for Product Safety and Standards (OPSS) is the policy lead and appointed Market Surveillance Authority for Ecodesign Regulations in the UK. The normative levels for NO_x emission have been adopted in

the gas industry's guidance on hydrogen appliances, most notably the PAS 4444 produced by BSI on hydrogen-fired gas appliances.

Emissions from gas burning appliances in domestic properties are further controlled through adherence to the ventilation requirements in the Building Regulations, including through the accompanying approved documents.

In the event of any national roll out, HSE would expect that work in relation to any domestic gas fitting needs to be in accordance with appropriate standards.

Appliance safety

Gas appliances and fittings will be designed and manufactured in accordance with recognised designated standards which specify how the appliance/fitting should be made and are usually produced by industry-led, technical committees.

Conformity assessment bodies are accredited by the United Kingdom Accreditation Service (UKAS) who have the responsibility of their oversight and governance. HSE is not a Conformity Assessment Body for appliances and does not play a role in the conformity assessment procedure for gas appliances.

Risk Mitigation Measures

The following section considers the suitability and effectiveness of the domestic mitigations presented in the gas distribution industry's paper Hydrogen Risk Mitigations GDN risk mitigations selection proposal rev 1.0. Upstream mitigation proposals and incorporation of mitigations into the assessment of risk is considered later in Section 11. The chapter on the National Hydrogen Safety Assessment (Section 14) considers how they would be deployed across different settings in the event of a roll out of hydrogen heating.

This section outlines the mitigations proposed by the gas network industry and how they would be applied:

Existing and applied mitigations

The gas network industry has confirmed that the following, currently existing, mitigations would be maintained:

- Routine voluntary/and or obligated appliance inspection and intervention
- Pre-existing ventilation.
- Continued relocation of unsafe internal meters

Universally applied mitigations

The report proposes that all downstream assets and installations will undergo inspection, validation, and possible intervention as part of the conversion process.

HSE notes that this would be expected to have a significant positive impact on domestic gas safety.

All network and end-user assets and appliances will be validated as suitable for the transportation or combustion of hydrogen. For end-users, this will require new hydrogen appliances (installed during or prior to conversion).

Remote hydrogen detectors

The report indicates that remote hydrogen detectors, with the functionality to remotely notify the emergency call centre to the presence of a leak, enabling the dispatch of a First Call Operative (FCO) independent to the public reported escape (PRE) process, show significant contributions to risk reduction. It is proposed that all end-users would utilise hydrogen detection.

HSE considers that the deployment of domestic hydrogen detectors presents a positive safety mitigation, however, robust consideration of the following must be undertaken:

- Reliability issues and decay of protection levels over time due to detectors falling into disuse.
- The ability for hydrogen detectors to detect all leaks, for example, leaks under floorboards.
- Protection of vulnerable users e.g. those with impaired cognitive ability or reduced senses. Options such as configuring gas detectors to stop the supply automatically via the meter EFV or separate AIV should be further considered.
- User behaviour can change in the presence of automation such as the proposed use of remote hydrogen detectors linked to emergency response. There is an evidence gap around how people will respond if they know an alarm will trigger a remote response.

Overall, whilst deployment of remote hydrogen detectors is positive, the level of sophistication and efficacy of gas detection still remains to be demonstrated.

Excess Flow Valves

It is proposed to install two Excess Flow Valves (EFVs); a mechanical one at the outlet of the ECV and a second one within the gas meter outlet. Mechanical EFVs are currently used on medium pressure services to isolate the supply when the flow exceeds a pre-set threshold, mitigating the risk of large releases downstream. These would be retrospectively installed at the meter of all pressure tier supplies to all end-users (subject to gas usage and EFV capacity). Electronic EFVs within the meter will also be utilised. EFVs have the ability to prevent high flows commensurate with an open-end pipe, which may result in high hydrogen concentrations. HSE considers

that they are a recognised and readily available technology, with good reliability, which are expected to be effective in reducing the worst cases of domestic gas explosion.

Fitting the EFV's at the ECV does not protect the property from service pipe damage or interference and only protects against larger leaks. The electronic device within the meter is to be set commensurate with the total gas demand of the property thus providing greater sensitivity to smaller leakage and as such requires a management system to ensure correct setting. However, the replacement of metallic services with PE is expected to bring about a significant reduction in service pipe leaks, especially those where gas is able to move through the ground and enter a property. Leaks caused by mechanical interference during excavation will leak to atmosphere predominantly.

Mitigations to be applied by exception

Alternative energy solutions

Where hydrogen mitigations are not practicable, users can swap to an alternative energy solution.

EFVs on downstream spurs

Depending on the size and configuration of the gas system within a domestic setting, it may be appropriate to consider applying an EFV to a spur leading to an appliance(s). This would be informed by a site-specific conversion assessment.

Thermal Cut of Valve (TCO) at the meter

TCOs can cut off the gas supply if heat is detected. It can mitigate gas contributing to a house fire. Application would be informed by site-specific conversion assessment. HSE notes that further supporting evidence may be expected in order to support future justification if discounted for wider application.

Additional ventilation

The evidence reports that ventilation (both to external and internal locations) reduces the probability of flammable concentrations of hydrogen accumulating. It is also anticipated to improve performance of other mitigations, such as detectors, by encouraging the diffusion of a leak through a building, which improves detectability. It should be noted, however, that this would also increase the spread of smoke and fire and so the application of internal ventilation should be considered holistically with other risks.

However, the report notes the challenges associated with additional ventilation related to customer behaviour. It is anticipated that customers will not tolerate intrusive works to their homes, such as installation of ventilation, and even if it is installed, it would be susceptible to being blocked up and so its effectiveness as a mitigation is expected to be compromised.

The proposal therefore considers that additional ventilation is not suitable as a 'universal' measure but one that would be applied on a case-by-case basis during conversion planning. The decision making therefore will need to be made using a site-specific conversion assessment.

HSE considers this a practical approach to the issue of additional ventilation. Assessing the need for additional ventilation on a case-by-case basis, for example where joints exist within small, enclosed spaces (e.g. in meter cupboards or kitchen cabinets) ventilation to the room (where ventilation to outside the building is not possible) and implementation on a case-by-case basis could assist with both gas detection and gas dilution. Site specific risk assessment would need to consider other legislation related to building safety.

There will be meters within confined spaces that remain difficult to ventilate. The application of mitigation measures will need to be considered holistically for a given installation.

Local hydrogen detectors

Local detectors (that would alert residents) have only been considered to be applied by exception as the remote detectors provide a much larger risk reduction and are identified as the preferred option. HSE notes this but also highlights the considerations discussed above relating to the demonstration of the effectiveness of remote detectors.

Proactive relocation of internal meters to outside locations

The report states that 45.9% of meters in the UK are located internally. Some of these could be expected to be identified for relocation following site-specific conversion assessment. It is not proposed to relocate every internal meter to an outside location as it is not judged to be achievable due to a range of factors including physical obstacles, no safer outdoor location being available, listed building with constraints on modifications. As such, it is proposed that meter relocation to outside will be considered on a case-by-case basis following individual risk assessment.

HSE supports the relocation of internal meters to outside due to the significant impact this has on individual risk. However, HSE recognises the constraints presented by the gas network industry. HSE considers the proposal to relocate meters outside following individual risk assessment to be appropriate. HSE notes the commitment for meter relocation even if the meter is determined not to be unsafe in its internal location by the assessment.

Discounted mitigations

Routine downstream inspection after conversion

It has been considered whether the mandating of annual gas safety inspection for all domestic residences, either through law or home insurance policies, would be

beneficial. The gas network industry considered that this would require a large increase in the qualified workforce and would be at a significant cost to the UK (including time accessing properties etc.) without providing a proportionate increase in gas safety.

Smart detectors

Smart detectors (linked to the operation of AIVs) have been discounted due to their anticipated technological readiness levels in 2032. HSE would expect to see the potential for this mitigation to be explored further as such technology evolves. HSE concurs with the evidence provided that a greater risk reduction could be achieved with the development of smart detectors.

Proactive relocation of all internal meters to outside locations

It is not proposed to relocate every internal meter to an outside location as is not judged to be achievable due to a range of factors including physical obstacles, no safer outdoor location being available, listed building with constraints on modifications. As such it is proposed that meter relocation to outside will be considered on a case-by-case basis following individual risk assessment.

HSE supports the relocation of internal meters to outside due to the significant impact this has on individual risk. However, HSE recognises the constraints presented by the gas network industry.

Training and Competence

Work carried out on gas fittings that are downstream of the ECV in domestic premises must be conducted by gas engineers with the appropriate competence and qualifications. The employers that engineers work for must be a member of a class of persons approved by the Health and Safety Executive, i.e. they must be on the Gas Safe Register. To enable compliance with GSIUR a training specification was developed by EU Skills and approved by the Gas Industry Standard Setting Forum (Interim Hydrogen Training Specification Utilisation Sector, IGEM 5) which was reviewed by HSE. The training specification was considered to address the domestic core competencies necessary to ensure competence of engineers conducting gas work on 100% hydrogen gas fittings in a domestic environment. Limitations have been placed on the training provision, which is only available to engineers who already hold specific natural gas qualifications and have at least 1 years' experience. HSE notes that developments and new findings such as the phenomenon of air ingress, will need to be considered by the training provision, with the training specification and training provision updated periodically to capture standard updates.

HSE has not received information on how training provision would be rolled out at scale in the event of a 100% hydrogen roll out. With 76,000 businesses on the GSR register and 150,000 engineers, anyone doing gas work in a domestic environment will need appropriate training and therefore any plans for a 100% hydrogen roll out will need to consider the development of a hydrogen competent workforce, and the

ability / capacity of training providers to deliver that training at scale. It is noted, however, that any national roll out will be a prolonged process over many years. Whilst competence to work on downstream hydrogen installations will require understanding of different requirements and parameters, and hence different qualifications, it is not foreseen that there is any technical reason why existing registered gas engineers shouldn't be able to readily qualify to work with hydrogen.

The training specification considered in this review only covers competence to work on domestic, downstream gas installations; it did not cover commercial gas installations. Training to conduct work on industrial gas installations is not generally covered by the Gas Industry Standard Setting Forum.

Conclusions

Overall, HSE considers that it is potentially feasible to convert the domestic natural gas system for use with 100% hydrogen for heating. The work submitted to HSE constitutes a developing evidence base that is building towards a demonstration of how the risks could be managed in line with regulatory requirements in the event of a roll out at scale. However, a full evidence demonstration has not been made at this time.

In particular, HSE notes that air ingress is a developing and evolving area of research and complete demonstration has not been made to be able to determine whether or not the relevant risks to domestic settings can be appropriately managed and mitigated at a national scale. The evidence submissions on air ingress indicate that this issue has the potential to be successfully resolved. However, if effective mitigations cannot be established, this issue represents a barrier to the feasibility of the roll out of hydrogen into domestic settings at a national scale. At this stage this represents a very significant evidence gap.

HSE notes the overall reliance on the principle of site-specific risk assessment using location specific data and conditions to determine the replacement of unsuitable materials and the mitigations to be applied by exception. At scale this could lead to a degree of variability in its application simply due to the extent of the decision-making being undertaken. The gas distribution industry would need to ensure that the consistency of decision making is carefully planned and managed at scale. HSE expects that, initially, a degree of conservatism would be incorporated into any risk-based decision making to account for the uncertainty associated with the use of a novel technology.

HSE considers that evidence on the compatibility of typical materials used downstream of the ECV within domestic and small commercial premises shows that most conventional materials are acceptable for use in hydrogen service. Currently not all fittings and sealants used in downstream systems have been demonstrated

as suitable for hydrogen service. However, it is anticipated that these issues should be able to be resolved and should not be considered a limiting factor.

HSE considers that the evidence demonstrates that there will be some non-conforming or unsuitable materials in some properties that would need to be replaced prior to any conversion. HSE notes that the installation of lead has not been permitted for many years but currently, in natural gas service, there is no requirement to remove it unless it is damaged or leaking. Evidence from the gas network industry confirmed that where found, *“lead will be replaced ahead of any hydrogen conversion – as is current practice under natural gas operation”*. However, for use with hydrogen there remain concerns over the condition and integrity of legacy lead piping and jointing such that it is likely that legacy lead pipework would also need to be addressed. Further supporting work to identify failure mechanisms and failure frequency would likely be required to justify any use in hydrogen service.

The gas distribution industry has confirmed that non-conforming materials would be replaced prior to any future conversion. Effective removal of these non-conforming materials requires effective identification. HSE considers that additional means of confirming the suitability of materials shall be required beyond that of visual inspection proposed by the gas distribution industry. This represents an evidence gap at this stage of HSE’s assessment. The gas distribution industry would need to consider and develop alternative/supplementary approaches to visual inspection that could be deployed prior to any hydrogen conversion.

HSE notes that smart detectors have been discounted. However, HSE would expect to see the potential for this mitigation to be explored further as technology evolves. HSE concurs with the evidence provided that a greater risk reduction could be achieved with the development of smart detectors.

Section 10.2 Multi Occupancy Buildings

It may be feasible to repurpose existing gas network infrastructure associated with MOBs. However, a full demonstration of how the risks could be managed in line with regulatory requirements has not been made at this time.

The evidence indicates significant system replacement or remediation would be required prior to repurposing. Conformity with industry standards would be expected in order to satisfy regulatory requirements.

The research on the phenomenon of air ingress is limited to simple, domestic settings. This represents a significant evidence gap for MOBs.

Asset condition and suitability assessment represents a challenge. A methodology underpinning inspection and assessment would need to be developed.

Effective collaborative work between the gas and housing industries would be required to ensure compliance with both building and gas safety legislation.

Introduction to Multi Occupancy Buildings (MOBs)

The term MOB encompasses all properties that contain multiple dwellings and could consist of a mix of residential properties and commercial business units. It has been identified that flats make up 21% of GB's domestic heat load. The repurposing and installation of gas network supplies to MOBs has been considered as part of the wider network infrastructure required for 100% hydrogen heating.

Typically, MOBs are supplied with gas via the local distribution system (LDS) from the low pressure (0 – 75 mbar) network in common with many residential domestic premises. The following section considers the gas supply and assets upstream of the Emergency Control Valve (ECV). The upstream evidence assessment in relation to MOBs considers a range of end of use settings, including buildings that are deemed to be high risk (HRB), which contain at least 7 floors or are at least 18 metres in height.

The Quantitative Risk Assessment for MOBs is considered separately in this report.

HSE's Evidence Assessment

Building surveys

The Task 2 – Building Surveys submission⁸⁷ reported on gas network industry surveys of 18 multi-occupancy buildings of various heights, types, ages, materials, gas installations and gas usages, that were undertaken to:

- identify issues specific to building types/architectures and gas installations that could affect a conversion to hydrogen; and
- collect data that would feed into the development of the QRA, the analysis of network capacity, the assessment of ventilation of enclosures, ducts and dwellings, and the assessment of fittings present in gas installations in MOBs.

The buildings surveyed were constructed between 1875 and 2023 and were of various construction types including brick, concrete, stone, steel frame and timber frame construction. Some listed buildings and buildings within conservation areas were also included in the survey.

The surveyed buildings include network pipelines that were installed between 1967 and 2023, and that are either external or internal to the building with the internal ones being either ducted or un-ducted. MOBs with meter banks located in a basement, at each floor and in a separate enclosure were also included in the survey.

The study found that, out of the eighteen buildings that were subject to survey, only two were found to be compliant with IGEM Standard /G/5: Gas in multi-occupancy buildings.

These standard addresses gas network installations to and within multi-occupancy buildings and the individual dwellings and commercial units within such buildings. HSE considers that, while useful, the sample size is limited when considering the wider MOB population and, in particular, risers within ducts and non-compliant energy centres. HSE notes that the surveys identified a number of issues related to non-compliance with IGEM G/5. A number of concerns were identified, including pipework of unsuitable design and assembly, lack of required ventilation, especially within riser enclosures unable to be vented externally, gas supply pipework in garage areas potentially at risk from vehicle fires or impact and gas risers within stairwells etc. These issues were not necessarily associated with specific material compatibility but with pipework system, fittings, routing and pipework design. Many of these issues would likely require a full replacement of the associated gas network supplying the properties as repair or partial replacement may be impractical.

⁸⁷ Task 2 – Building Surveys, ROSEN, 2024

The networks have indicated that all MOBs would, in the event of a roll out, be subject to site-specific survey and compared with the requirements of relevant legislation and current standards such as IGEM/G/5 prior to conversion. HSE notes that, if the rate of non-compliance observed in the sample survey was seen more widely within the MOB population, this could impact on the level of gas network replacement required.

Network capacity

The MOB surveys were also used to assess the feasibility of the network to supply end users within MOBs. The Task 3 – Network Pipeline Capacity project⁸⁸ examined the effect of pipe diameter, altitude, pressure drop associated with fittings and layout, and the minimum pressure required for the safe operation of hydrogen appliances. Modelling was carried out for ten properties.

Of the ten properties, four exceeded velocity limits when hydrogen supply was considered. However, HSE notes that the 20 m/s velocity limit would need to be examined further to ascertain whether lifting the value is safe to do. This represents an evidence gap at this stage.

The model appears to not have been validated against tests carried out within the properties examined, and the wider population has not been considered. HSE notes that significant work may be required for individual properties to ensure compliance with standards.

Ventilation

The Task 4 – Ventilation Report⁸⁹ evidence submission considered:

- ventilation requirements for meters, risers and laterals inside buildings.
- ventilation requirements for meter banks and energy centres with hydrogen and how they compare with ventilation requirements for natural gas and updating Table 6 of IGEM/G/5 Edition 3 [3].
- ventilation requirements for typical ducts with hydrogen and how they compare with ventilation requirements for natural gas and updating Table 8 of IGEM/G/5 Edition 3.
- the feasibility of adding ventilation to existing ducts, enclosures and buildings, which will need to be positioned so as not to compromise fire safety if located in a fire compartment.

The following conclusions were presented:

⁸⁸ Task 3 – Network Pipeline Capacity, ROSEN, 2024

⁸⁹ Task 4 – Ventilation Report, ROSEN, 2024

Individual Dwellings

In MOBs, a typical meter location in dwellings is a kitchen cupboard. IGEM/H/2 (draft) recommends that the following criteria are met for a kitchen cupboard to be a suitable location for a hydrogen meter:

- 125 cm² vents top and bottom of meter cupboard.
- 100 cm² high level external vent in room containing meter & 75 cm² door undercut.
- Hydrogen audible alarm.

Hallways have been found to be a more suitable location for meters as they tend to be naturally better ventilated compared to other rooms. IGEM/H/2 (draft) defined a hallway as a permissible location for a hydrogen meter if:

- a hallway has a height equal to or more than 2 storeys and at least 5 room doors (including one outside door) or
- a hallway/open plan living area has a volume of at least 80 m³ if the hall is single storey (or is part of an open plan living area)

The submission noted that it is likely that these criteria will rarely be met in MOBs. In addition, relocation of meters to a hallway is generally unlikely to be a viable option for MOBs due to space constraints and the requirements for network pipelines to take the shortest route.

The criteria referenced above, would also apply to boilers located in kitchen cupboards. Most of the boilers in the MOBs surveyed were in a kitchen. For a kitchen there is a requirement for it to either be connected directly (by means of one internal door) to the hall or to be an open plan living area (with a volume larger than 80 m³). The top of the boiler case should be less than 0.5 m below the ceiling/roof line and the kitchen/utility room should have an Approved Document F compliant extract fan, with a restricted stop at 100 cm².

The submission notes that these conclusions are based on a study that did not include MOBs, and that it is currently unknown whether the air permeability of MOBs would be similar and whether the conclusions would be applicable to MOBs. HSE considers that this represents a significant evidence gap.

The submission recommends that air permeability of a range of MOBs, representative of the UK MOB stock, should be measured to determine whether air permeability results follow a similar trend to other non-MOB properties. HSE would consider this a critical element for a safety demonstration.

Common Areas

The submission identified that un-ducted screwed risers and laterals will require ventilation directly to outside air. Basements and cellars containing below ground entries and network pipelines will require ventilation to outside air. Currently the free area of ventilation required is not explicitly specified but the submission suggests that this can be determined as part of a hazardous area classification.

The submission recommends that common areas within MOB's are required to comply with DSEAR and a hazardous area classification in accordance with IGEM/SR/25 Supplement 1. This will be required to demonstrate compliance and ensure the free area of ventilation currently provided by existing vents is adequate with hydrogen.

HSE supports the conclusion that un-ducted network pipelines, basements and cellars containing below ground entries and network pipelines will have to be assessed using IGEM/SR/25 Supplement 1 prior to a conversion to hydrogen.

Meter Banks

The evidence submission suggests that meter bank installations which are compliant with IGEM/G/5 Edition 3 will have more than adequate ventilation for hydrogen.

Ventilation would need to be provided at high and low levels within the meter bank enclosure. Low level ventilators would need to be positioned 150 mm above the floor. High level ventilation would be installed as close to the highest point within the ventilated space as possible. Unventilated voids at high level would need to be avoided, and where necessary, soffit ventilation or apex vents installed.

HSE notes that meter banks installed before 2006 (prior to the publication of IGEM/G/5 Edition 1) are likely to require additional ventilation to meet the requirements of IGEM/G/5 Edition 3, during any conversion. The submission recommends that, to account for the materials factor introduced in IGEM/SR/25 Edition 2 Supplement 1, an assessment should be undertaken on each meter bank to ensure materials and fittings are fit for use with hydrogen prior to any conversion.

The submission confirmed that ventilation within meter banks which is non-compliant with IGEM/G/5 Edition 3 will require a hazardous area classification in accordance with IGEM/SR/25 Edition 2 Supplement 1 to determine whether ventilation is more than adequate.

HSE supports the conclusion that the meter bank installations will have to be compliant with IGEM/SR/25 Edition 2.

Ducts

The report notes that the IGEM/SR/25 Edition 2 calculator does not provide an option to assess the adequacy of ventilation within ducts. The ventilation requirements for ducts have therefore been calculated from first principles using IGEM/SR/25 Edition 2 and IGEM/SR/25 Edition 2 Supplement 1.

The submission suggests that ducts meeting the ventilation requirements of IGEM/G/5 Edition 3 will provide more than adequate ventilation for hydrogen.

It also confirmed that:

- Ventilation should be provided at high and low levels within ducts.
- Ducted screwed risers and laterals will require ventilation directly to outside air.
- Risers installed within ducts, of a cross-sectional area less than 0.05 m², constructed before 2022 (prior to the publication of IGEM/G/5 Edition 3) are likely to require additional ventilation to meet the requirements of IGEM/G/5 Edition 3, prior to conversion.
All ducted risers installed before 2006 (prior to the publication of IGEM/G/5 Edition 1) are likely to require additional ventilation to meet the requirements of IGEM/G/5 Edition 3, prior to conversion.

The submission recommends that:

- The ventilation requirements for ducts for hydrogen should be as the current requirements within IGEM/G/5 Edition 3.
- Ventilation within ducts which is non-compliant with IGEM/G/5 Edition 3 will require a hazardous area classification in accordance with IGEM/SR/25 Edition 2 Supplement 1 to determine whether ventilation is adequate.
- Where ducts containing welded fittings are not ventilated, or not ventilated to a normally occupied space, a risk assessment should be undertaken with appropriate mitigation considering:
 - Increased inspection and/or leakage surveys to ensure a leakage in a non-occupied space does not go undetected
 - Hydrogen detection alarm systems

HSE considers that ventilation has been considered appropriately in the evidence submissions. However, it is clear that an assessment of ventilation requirements would need to be conducted at each property to ensure compliance with relevant legislation and standards prior to re-purposing to hydrogen.

Energy Centres

The report notes that energy centres (a centralised energy centre that provides primary space heating and domestic hot water) require ventilation to outside air and that ventilation requirements can be determined using the methodology in IGEM/SR/25.

The report concludes that the energy centres assessed do not have sufficient ventilation free area to limit the overpressure in the case of an explosion to 35 mbar as per the requirements of IGEM/GM/8 Part 2 Edition 2 for both natural gas and hydrogen.

The energy centres assessed would not provide sufficient ventilation to limit the overpressure in the case of an explosion to below 340 mbar (below building strength levels) for both natural gas and hydrogen.

The report recommends that:

- A hazardous area classification in accordance with IGEM/SR/25 Edition 2 Supplement 1 will be required for all energy centres prior to a conversion to hydrogen, to ensure compliance with DSEAR.
- Energy centres which are classified as Zone 1 or Zone 0 (with hydrogen) should be assessed to determine whether there is sufficient ventilation to limit overpressure during an explosion to 35 mbar in accordance with IGEM/GM/8 Part 2 Edition 2.
- Energy centres which are classified as a Zone 2 or Zone 2 NE (with hydrogen) should be assessed to determine whether there is sufficient ventilation to limit overpressure during an explosion to 340 mbar in accordance with Building Regulations 2010 Approved Document A (Structure).
- If ventilation levels are found to be unacceptable, a risk assessment should be carried out considering:
 - a. Installation of additional ventilation, if possible.
 - b. Installation of ATEX rated equipment, to reduce likelihood of ignition.
 - c. Installation of a hydrogen detection system which automatically isolates the hydrogen supply and is linked to the building energy management system.
 - d. Frequent leak checks by a competent person.

HSE considers that ventilation for energy centres has been considered appropriately in the evidence submissions. However, it is clear that an assessment of ventilation requirements would need to be conducted at each property to ensure compliance

with relevant legislation and standards prior to re-purposing to hydrogen. The hierarchy of control outlined above appears to be appropriate. Frequent leak checks would be considered an additional control following application of A-C in the hierarchy.

Overall, HSE considers that the ventilation has been considered appropriately in Task 2 – Buildings Survey project 18198⁹⁰. However, HSE notes that studies carried out to assess how hydrogen affects the requirements for ventilation and explosion relief identified several gaps that require resolution. Currently these gaps remain unresolved.

The population and variability of building types would necessitate site-specific assessment for ventilation requirements to be conducted and steps taken to ensure that network supplies conform to the relevant standard. If the assessment conducted identifies legal or standards compliance issues, these would need to be resolved prior to re-purposing.

In addition, in many cases the ventilation required to be installed for hydrogen repurposing is not under the control of the gas network operator during design, construction or operation. The network operator has no control over any building modifications that may be necessary to meet other statutory duties, but which may impact upon the gas network.

Further collaborative work between the gas and housing industry is likely to be required to ensure compliance with both building and gas safety legislation. Any work may also need to be mindful of other work initiated in response to the findings of the Grenfell Fire Inquiry.

Materials and fittings

The report Task 5 – Materials and Fittings⁹¹ provided evidence relating to the assessment of material compatibility, performance of sealants, suitability of legacy fittings (butterfly valves, legacy valves, flexible connectors, syphon standpipe, dip pipe, dip pipe collars, dust trap etc.) and legacy material (copper, old PE, lead).

After compiling a list of the most common materials found in MOBs and undertaking a view of the applicability of the Hydrogen Ready Components (HRC) scoring system to MOBs, a total of 70 assemblies were evaluated to determine the overall risk score for use in hydrogen.

The following recommendations were made:

- All MOBs should be assessed for compliance with IGEM/G/5 Edition 3, prior to re-purposing to hydrogen.

90 Task 2 - Buildings Survey - Project 18198 - report to SGN, Rosen, 2024

91 Task 5 - Materials and Fittings, Rosen, 2024

- When available, the updated HRC tool should be used to update the scores of the components assessed.
- Valves and regulators commonly found in MOB's have failed the assessment; however, this is owing to the high natural gas risk score of the component, not their use in hydrogen. It is recommended that testing is undertaken to understand any further impact of hydrogen on valves commonly found in MOB's.
- Testing should be carried out to understand any further impact of hydrogen on screw threaded joint sealants commonly found in MOB's, including historical sealants which may no longer be used.
- Testing should be carried out on screwed joints containing sealants such as Boss Gastite and Plumber's Mait.
- Testing is required to understand any further impact of hydrogen on insulation joints.
- Prior to a conversion to hydrogen, it is likely that the gasket material within any flanged joints would be unknown. It is therefore recommended that gaskets within flanged joints are replaced during the conversion, with gaskets qualified for use with hydrogen.

HSE considers that the list of common components that has been produced is informative. However, this represents current standards in relation to items such as pipeline isolation valves where a variety of valve types would be present in the MOB population due to historical use. In addition, HSE notes that, of the seventy assemblies evaluated, over fifty percent failed the assessment; all valves failed.

HSE considers that, while some of the network pipe materials used within the surveyed MOB's would generally be considered as compatible with hydrogen, there will be significant challenges in identifying materials and system configuration in situ to determine condition and suitability.

As per domestic and small commercial properties, the use of pipe thread sealants requires further scrutiny and raises particular concern as it has been seen to be used in larger screwed risers in some buildings. The risk of joint leakage within such systems, including those of smaller diameter, requires further evaluation and scrutiny.

Overall, comprehensive details relating to the design, location, installation, testing and condition of materials and fittings present within the MOB population are absent in many cases, making any determination on the suitability of these for hydrogen use challenging. A full list of the fittings in use has been identified as a knowledge gap and details of historic maintenance and repair are also not available. Doubt also exists in some areas regarding construction methods, including joint types and jointing materials.

As observed in the MOB surveys, there were a number of non-conformances identified that would likely be exacerbated if repurposed to hydrogen service. HSE notes the recommendation that all MOBs should be assessed for IGEM/G/5 compliance prior to re-purposing to hydrogen. However, no further assessment of how this would be carried out or the likely non-compliance rate has been provided.

Influence of hydrogen on network installation and maintenance

Evidence was presented relating to the feasibility of continuing to use the current jointing and repair systems used in riser networks if they are repurposed to carry hydrogen. The *Task 6: Testing with hydrogen* report considered⁹²:

- Suitability of jointing methods typically used in MOBs with hydrogen
- Suitability of existing expansion bellows and flexible metallic hoses with hydrogen
- Suitability of existing techniques used for the isolation between existing live systems and risers/laterals to be commissioned
- Suitability of jointing compounds with hydrogen
- Suitability of existing insulation joints with hydrogen
- Suitability of previously repaired, altered or replaced pipework for repurposing

The gas network industry identified that a range of components such as screwed joints, press fit (Geberit) joints, and renovation and repair systems used in MOBs require further testing and analysis to assess the feasibility of continued use in riser and lateral networks should they be re-purposed to hydrogen. Samples were recovered from sites along with newly assembled samples to enable the following testing:

- Initial integrity test: All test assemblies are subjected to an air test at maximum operating pressure (75 mbar) for 15 minutes to establish initial integrity. Integrity with Hydrogen: All test assemblies are pressurised with hydrogen at 75 mbar for 15 minutes to establish if the initial integrity has been compromised when using hydrogen.
- Simulated recommissioning integrity test: If integrity remains with hydrogen, one of each component is then pressurised with hydrogen up to 350 mbar for 15 minutes to confirm that there would be no issues should the installation be subjected to a standard site pressure test as part of the recommissioning process when re-purposing to hydrogen.
- Permeability to Hydrogen test: One of each component is pressurised with hydrogen at 75 mbar for up to 3 weeks to establish whether permeation of hydrogen takes place through the fully installed component.

92 Task 6 – Testing with Hydrogen, ROSEN, 2024

- Exposure to Hydrogen test: Samples of each sealing material are exposed to hydrogen for the suggested time periods (1 week, 1 month, 3 months, 6 months) and any change in mechanical properties assessed following exposure.

The site samples provided by SGN were subjected to a 75mbar pressure test with air to establish the integrity of the sample prior to undertaking any further testing with hydrogen. Of ten site samples subjected to the 75mbar integrity test with air, six have shown a pressure drop of up to 2.5mbar over a 15-minute period, three could not contain the internal pressure due to visible leaks from the test component (and will therefore not be used in any further tests with hydrogen), and one sample maintained the applied pressure without any pressure drop.

HSE notes that the testing results present a significant failure rate. If extrapolated to the wider MOB population this would require significant levels of replacement.

HSE understands that the longer-term exposure to hydrogen tests will be undertaken to provide additional evidence and should be fully completed by December 2024. At this stage this represents an evidence gap.

HSE concludes that further work would be required to determine the variety of system conditions and repair methodologies that are suitable for re-purposing.

Combined effect of hydrogen and thermal loading on material integrity

The submission *Task 7 – Combined Effect of Hydrogen and Thermal Loading on Material* ⁹³considered evidence relating to:

- Validity of current diameter, height, lateral length, material limitations and permitted jointing methods.
- Susceptibility of low strength steel to hydrogen cracking when subject to stresses resulting from expansion and contraction, and effect of hydrogen on likelihood of failure of risers, which do not have the required allowance for expansion and contraction.
- Applicability of existing thresholds, including minimum permitted wall thickness corrosion before isolation. and corrosion damage categories for pipe designed to operate at stress levels not greater than 40% Specified Minimum Yield Strength with hydrogen.

The following conclusions were presented:

- When considering a conversion to hydrogen service, the laterals meeting the minimum unrestrained length requirements specified in IGEM/G5 Edition 3 were found to have a fatigue life greater than 100 years.

⁹³ Task 7 – Combined Effect of Hydrogen and Thermal Loading on Material Integrity, ROSEN, 2024

- Laterals not meeting the minimum length requirements specified in IGEM/G/5 Edition 3 were found to have a reduced service life with hydrogen. This is primarily due to the laterals experiencing stress levels above the specified minimum yield values due to thermal loading.
- The diameter limit of 50 mm and height limit of 20 m remain valid with hydrogen for threaded carbon steel risers and laterals.
- The minimum lengths of unrestrained 22 mm and 28 mm internal and external press-fit stainless-steel laterals specified in IGEM/G/5 Edition 3 remain valid with hydrogen.
- The minimum network pipeline thickness requirement for resistance to buckling and structural stability remain the same with hydrogen.

Based on these conclusions, the evidence submission made the following recommendation:

- Stress analysis and fatigue analysis of network pipelines comprising laterals that do not meet the recommended minimum unrestrained length specified in IGEM/G/5 Edition 3 will be required to confirm whether their remaining life is acceptable for a conversion to hydrogen.

Overall, HSE considers that the lack of validation of the current network pipe and fittings within the MOB population prohibits a comprehensive review to be carried out. While the gas network industry has indicated that a full risk assessment of a MOB would be required prior to any conversion.

Electrical safety

The evidence submission Task 8 – Electrical Safety Report⁹⁴ considered the suitability of separation distances between electrical services and gas systems with hydrogen. This considered whether:

- the standards to which electrical equipment is currently specified relates to natural gas only, or to any flammable gas
- requirements for electrical equipment are impacted by hydrogen being gas group IIC versus gas group IIA for natural gas
- the existing separation distance between natural gas pipes/meter and electrical equipment remains the same with hydrogen.

The research projects undertaken presented the following conclusions:

- To comply with the requirements of DSEAR, meter banks, energy centres and common areas within MOBs must be risk assessed to determine the location and extent of explosive atmospheres, and their classification once

94 Task 8 – Electrical Safety Report, ROSEN, 2024

repurposed for use with hydrogen. The risk assessment includes hazardous area classification of the pipework and components.

- For pure hydrogen, the necessary air change rate per hour to allow classification as Zone 2 NE is increased from 0.5 (for natural gas) to 1.5 air changes per hour (ACH). Where this cannot be achieved, uncertified electric lighting and other electrical equipment will need to be relocated or replaced with certified gas group IIC equipment.
- It is expected that there will be no requirement for a hazardous area classification for hydrogen in a domestic environment (individual dwellings) as DSEAR does not apply.
- The minimum separation distances between electrical equipment and gas equipment are independent of the gas being transported and research projects have concluded that these do not need to change.
- Lightning protection requirements are independent of the gas being transported and are in place to protect the pipe structure from damage and existing IGEM/G/5 guidance can remain unchanged.
- Research indicates that most incidents relating to electrical safety are due to non-compliance with current standards.
- Any electrical equipment located in the vicinity of gas installations should be assessed for compliance by a competent person, prior to the conversion of MOBs to hydrogen.

The risk of damage to electrical cables in MOBs, due to the presence of gas pipework, leading to electrocution, is deemed one part of this evidence submission. Overall, HSE considers that the conclusions of the submission suitably consider this element of electrical safety.

The other part of this evidence submission is the ignition of an explosive atmosphere due to a release from the gas system within a MOB. HSE considers that the conclusions correctly identify that meter banks, energy centres and common areas within MOBS must be risk assessed, and hazardous area classification conducted to comply with DSEAR. HSE notes the recommendation that all MOBs should be assessed for IGEM/G/5 compliance prior to re-purposing to hydrogen, which includes the consideration of risk assessment and hazardous area classification.

HSE notes that the conclusions referring to the increase in ventilation from 0.5 ACH to 1.5 ACH for hydrogen is only relevant to those installations within the scope of Appendix 5 of IGEM/SR/25 i.e. un-obstructed locations around joints with an operating pressure not exceeding 100 mbar. HSE notes that where this cannot be achieved, i.e. areas which require zoning, it is not only electrical equipment which requires controlling; numerous other ignition sources should be considered, as per BS EN 1127-1:2019 e.g. mechanical equipment, hot surfaces, static electricity. The degree of control of each ignition source type varies based on the zone type and in some cases, the gas group.

HSE considers the statement within the evidence submission that domestic, individual dwellings are not regulated by DSEAR to be a misinterpretation. Work within a domestic premises still requires assessment of the risk and the other requirements under DSEAR to be fulfilled; some discrete elements of the regulations do not apply.

HSE considers that the work undertaken is informative and that the notes raised could be clarified and addressed within the Draft Standard for Converting Natural Gas Installations in Multi Occupancy Buildings to Hydrogen⁹⁵.

Fire protection measures

The *Task 9 – Fire Protection Measures*⁹⁶ considered the applicability of current requirements for fittings and components relating to the permissible leakage rate during, and after, a high temperature event where hydrogen is the gas being distributed.

The evidence concluded that:

- Due to a lower self-ignition temperature of hydrogen compared to natural gas, maintaining the test temperature of 650°C will be conservative, as it exceeds the 560°C self-ignition temperature of hydrogen. It is recommended that a value of 650°C for Procedure B is maintained.
- The existing high temperature testing parameters and leakage rate of BS EN 1775 Procedure A are applicable and are considered conservative in the transition to hydrogen. The potential energy contribution from a hydrogen fuelled leak will be less than that of natural gas.
- The existing high temperature testing parameters and leakage rate of BS EN 1775 Procedure B are applicable and are considered conservative in the transition to hydrogen. The potential energy contribution from a hydrogen fuelled leak will be less than that of natural gas.

Pressure testing

The *Task 10 – Pressure Testing*⁹⁷ report considered the applicability of test pressures, test criteria and purge velocity with hydrogen to MOBs and the suitability of existing equipment for purging operation in MOBs.

A review of the gas leakage and dispersion modelling of pure hydrogen undertaken as part of the H21, H100, HyDeploy, and Hy4Heat projects, was conducted to determine the maximum permitted leak. The following conclusions were presented:

⁹⁵ Draft Standard for Converting Natural Gas Installations in Multi-Occupancy Buildings to Hydrogen, SGN, 2024

⁹⁶ Task 9 – Fire Protection Measures, ROSEN, 2024

⁹⁷ Task 10 – Pressure Testing, ROSEN, 2024

- Projects to further investigate gas leakage and dispersion behaviour of pure hydrogen and hydrogen blends are ongoing. In the interim, whilst research is ongoing, a conservative approach should be adopted.
- It is recommended that the IGEM/G/5 hydrogen supplement includes detailed pressure testing requirements within the main body of the standard.
- It is recommended that the pressure testing requirements within the IGEM/G/5 hydrogen supplement specify a strength and tightness test during repurposing.

For the Network pipeline

- The testing requirements of SGN/PM/RL/1 are not in accordance with the requirements of IGEM/TD/3 or IGEM/G/5. It is recommended that SGN review and update SGN/PM/RL/1.
- For network pipelines, the pressure testing requirements stated in IGEM/TD/3 are the most conservative and should be adopted in the interim.

Overall, HSE considers that development of an appropriate pressure testing regime for existing network systems has not been completed. The test scenarios presented do not appear to be linked to credible failure mechanisms such as ageing or construction methods. Further work is required to quantify the risk associated with pneumatic pressure testing of ageing assets.

The use of pressure testing alone as an indicator of the condition of the upstream network is not accepted.

Purging hydrogen risers

The evidence submission 357 Purging Hydrogen Risers (MOBs) Final Report⁹⁸ presented the following overall conclusions:

- Changing from natural gas to hydrogen will not prevent successful purging of risers in MOBs using current procedures. Pipe diameters of those commonly seen in MOBs (up to 50 mm) purge efficiently even when minimum purge speeds are not achieved. Hydrogen purges tend to be more efficient than natural gas purges and pipe lengths are relatively short in MOBs compared to network purge operations.
- Current purge tooling and processes used for natural gas will work for hydrogen. Often purge speeds are dictated by the pipework being purged, the service supply and the vent pipe used. Purge speeds will be the same when displacing air during commissioning and they will accelerate as the transition to hydrogen occurs in the pipe being purged.

98 357 Purging Hydrogen Risers (MOBS), Steer Energy, 2024

- Direct purging of pipes creates small flammable volumes of mixed gas, these are small during routine purge operations and will not pose a significant increase in hazard with hydrogen.
- Direct purging of branched systems also creates flammable volumes of gas at the branch nodes. These flammable volumes can increase in size over time if left unpurged. Sequential purging of the branches, as per standards, removes these flammable volumes, leaving a safe completely purged system.
- Access to every flat is the biggest challenge on site when purging risers and this can lead to unpurged branches or laterals with associated flammable mixes being left over time.
- Indirect purging does not mitigate the creation of flammable mixtures in the case of lack of access to a particular branch in a riser.
- Branch isolation valves, lateral isolation valves and other valves, if fitted that section the riser system will mitigate the creation of large flammable volumes.

The majority of the experiments have investigated dispersion in partially purged systems. Routine purging has been confirmed during the setup of all the dispersion tests and is not seen as a challenge. The dispersion work has led to the following conclusions:

- If an unpurged branch is left, the flammable volume at the interface between purged and unpurged sections will increase over time. Pipe diameter is the dominant parameter that dictates the speed of mixing of the two gases.
- Gas dispersion occurs through a combination of buoyancy and diffusion. Buoyancy effects are diameter dependent becoming more dominant in pipe diameters greater than 50 mm. Below 50 mm gas dispersion is slow, being dominated by diffusion alone.
- Diffusion driven dispersion acts in the direction of concentration gradient from high to low reducing the concentration gradient and slowing subsequent diffusion. In vertical pipes, concentration gradients have been seen to act upwards or downwards.
- Buoyancy effects act preferentially upwards but also promote mixing of different density gases in horizontal pipes.
- In tests, hydrogen dispersion was up to twice as fast as methane dispersion.

The implications of leaving mixed volumes of air and fuel inside a portion of a riser are dependent on the flammability of the fuel. The flammability conclusions are:

- Flammable limits are gas dependent and dictate the flammable portion of any fuel air mix. Hydrogen has wider flammable limits than natural gas and so the volumes of flammable mixtures are larger. Routine sequential purging of branched risers does not create large flammable volumes. Mix volumes of concern only occur when an un-isolated branch is left unpurged for at least a number of hours or days. Most laterals are small, and if left unpurged, will not result in a large flammable volume.
- Volume calculations of purged vs unpurged sections of risers can identify the potential flammable volume that an unpurged branch could create.
- A calculator to assist with purged and unpurged volumes has been produced.
- Branches in risers can be treated as independent from one another if the volumes are small and diameters are 50 mm or below. Adjacent branches act as gas reservoirs.

Additional tests have been carried out to investigate likely overpressures generated from unpurged sections of pipe, the consequence conclusions are:

- Consequence tests have shown detonation is possible inside pipes of 1-inch and 2-inch diameter. This was done using artificially mixed gases to specific concentrations. Unpurged branches, if long enough, in the order of 5 m, could produce detonable mixtures if left unpurged over time.
- Adjacent volumes of non-flammable gas will reduce the magnitude of any overpressure.
- Consequence tests carried out during purging operations, at approximately one tenth the recommended speed and venting over a live ignition source, managed to demonstrate detonation, but the overpressure was only up to 3.5 bar, one tenth of those seen with the artificial stoichiometric mixtures.
- Pockets of gas can generate detonable volumes in pipes after a few hours, but no ignition sources are expected inside the pipeline.

The tooling and procedures used for purging operations on risers has been reviewed. The submission recommended that the tooling and processes for purging are reviewed with a stakeholder group. This should include purging processes and tooling for network applications as well as those for services and for MOBs.

Overall, HSE considers that the lack of accurate and comprehensive records of gas network systems within MOBs presents a challenge when carrying out purging. For example, while branch isolation valves and lateral isolation valves could mitigate against the creation of large flammable volumes these may not be present in all

circumstances. Gaining access to properties and pipework to determine system configuration represents a challenge.

The issue of the use of flame arrestors is also an area that requires further examination.

Feasibility Study: Hydrogen in MOBs

The submission Decarbonisation of Multi-Occupancy Buildings Feasibility Study: Hydrogen in MOBs, GDN Aligned Summary Report⁹⁹ investigated the potential of repurposing existing gas installations for hydrogen use in MOBs. The report identifies that the application of risk mitigation measures in 2-storey and 3-storey buildings could be similar to those applied in domestic settings as discussed in Section 12).

The report proposes a suite of universally applied mitigations for all other MOBs, i.e. mitigations to be applied in 100% of these MOBs. These are:

- A one-off riser inspection before conversion including an assessment of all existing assets against Gas Industry Standard;
- Building owner providing a one-off checking of the building strength to meet requirements before conversion;
- One-off downstream inspection before conversion;
- Installing one mechanical Excess Flow Valve (EFV) immediately upstream of the meter and one electronic EFV in the meter
- Installing 'Remote' hydrogen detectors - Local alarm function, plus remote notification to the emergency call centre to dispatch a First Call Operative (FCO).

The report also identifies a suite of mitigations for MOBs above 3 storeys to be applied by exception i.e. the application to be determined on a risk-based case by case basis. These are:

- Replacing gas risers with an energy centre for heating and replacing gas appliances with electric equivalents;
- Retaining boilers in dwellings but eliminating other gas appliances by replacing them as required with electric alternatives;
- Replacing network risers that are in poor condition;
- Upgrading non-compliant installations on existing assets to meet Gas Industry Standards;
- Installing additional ventilation;

99 Decarbonisation of Multi-Occupancy Buildings Feasibility Study: Hydrogen in MOBs, SGN, 2024

- Installing 'Smart' hydrogen detectors - Local alarm function, plus smart notification capability to other appliances, such as an Automatic Isolation Valve (AIV);
- Installing additional EFVs on the downstream network;
- Installing additional EFVs on the riser;
- Installing a Thermal Cut Off (TCO) device at the meter;
- Installing a TCO on the riser;
- Removing all gas from the building and replacing with an alternative energy supply.

The report concludes that, with universally applied risk mitigation measures and up to two additional mitigations where required (i.e. the installation of additional ventilation or AIVs and replacing existing risers with lower risk risers), around 99% of MOBs can be converted to hydrogen using repurposed assets. However, HSE notes that the network installations will need to be compliant with relevant legislation and industry standards.

The report concludes that there are around 1% of MOBs where it is likely that existing natural gas installations cannot be repurposed for hydrogen use at an economic cost. The following options are available for this small proportion of buildings:

1. Accept a small individual risk increase in a small minority of building types.
2. Implement additional risk mitigation measures that would reduce those individual risks, but at a disproportionate cost.
3. Remove gas supplies to these buildings and install an alternative energy source.

It is not clear to HSE how the report's conclusions of a 99% conversion rate reflect the rate of non-compliance demonstrated in the building survey evidence. If the non-compliance rate was extrapolated across the MOB population, then this would require significant system replacement or remediation prior to repurposing. This point may have implications for the feasibility of conversion on a cost basis. Subsequent recommendations made within the feasibility report demonstrate the need for further work to assess GB population of MOBs and gas installation configurations. HSE concurs that evidence needs to develop further in this area for definitive conclusions to be drawn.

Production of draft standard for MOB conversion

The submission of the Draft Standard for Converting Natural Gas Installations in Multi Occupancy Buildings to Hydrogen outlines additional requirements and qualifications for the conversion of natural gas installations in multi-occupancy buildings to hydrogen to be used in conjunction with IGEM/G/5 Edition 3.

The supplement outlines the principles required for the conversion of existing natural gas installations in multi-occupancy buildings to 100% hydrogen. It covers the principles required for the repurposing, renovating, and replacement of existing gas installations for hydrogen service and the decommissioning of existing gas installations.

This supplement provides the principles required to identify buildings and gas installations that are not suitable for repurposing and outlines remedial work that may be required prior to repurposing.

HSE notes that this standard is in development which should support any subsequent roll-out of hydrogen heating. The principles outlined above appear appropriate to support repurposing.

Production of interim procedures for MOB conversion

The gas network industry has developed interim procedures to demonstrate how the conversion of MOBs to 100% hydrogen could be managed: Safety Management Framework Management Procedure for Converting Natural Gas Installations in Multi-Occupancy Buildings to Hydrogen¹⁰⁰

The procedure describes the requirements for conversion of existing natural gas installations in multi-occupancy buildings to hydrogen operating at pressures not exceeding 75 mbar. For gas installations deemed unsuitable for conversion it provides guidance for decommissioning and alternative energy solutions. The gas supplied is assumed to be 100% hydrogen as specified by IGEM/H/1.

This procedure covers guidance for:

- The identification, selection and commissioning of network risers and laterals, installed in existing multi-storey buildings, deemed suitable for repurposing to hydrogen as they currently are.
- The requirements to identify buildings that are not suitable for repurposing in their current form and outlines the necessary replacement or partial replacement, renovation, alteration or repair of existing riser and lateral installations from the pipeline isolation valve (PIV) through to the supplier's emergency control valve (ECV) to enable hydrogen conversion.
- The identification, isolation and decommissioning of network risers and laterals, installed in existing multi-storey buildings, not deemed suitable for conversion to hydrogen.
- The provision of alternative arrangements in the form of an energy centre or an alternative option such as heat electrification, heat pump or heat network.

¹⁰⁰ Safety Management Framework Management Procedure for Converting Natural Gas Installations in Multi-Occupancy Buildings to Hydrogen, SGN, 2024

HSE recognises the work to progress these procedures but notes that further development will need to reflect changes in standards. The document highlights the need for site-specific surveys to determine compliance with relevant standards prior to conversion. Where non-conformities exist, HSE notes the commitment to rectify these prior to conversion as would be expected in order to satisfy regulatory requirements.

Conclusions

HSE concludes that it may be feasible to repurpose existing gas network infrastructure associated with MOB. However, the lack of asset data and the issues faced in assessing the condition and suitability of upstream systems within MOB is a challenge.

The basis of the reported 99% achievable conversion rate of MOB for use with hydrogen is not clear to HSE. The conversion rate is stated as being reliant upon the network installation being compliant with relevant legislation and industry standards in place at that time. The rate of non-compliance demonstrated within the building surveys, if extrapolated across the MOB population, would mean significant system replacement or remediation would be required prior to repurposing. Where non-conformities exist, HSE notes the commitment to rectify these prior to conversion as would be expected in order to satisfy regulatory requirements.

The research on Air Ingress is limited to simple, domestic settings. HSE considers this a significant evidence gap for MOB.

HSE considers that while the evidence provided via the Building Surveys was informative, the sample size is limited when considering the wider MOB population so may not be representative of the wider MOB population. The diversity of the MOB population and the variability and quality of asset records highlights the need to survey each MOB to ensure compliance with relevant industry standards. HSE accepts the gas distribution industry's proposal that each individual MOB system would need to be verified against the relevant legislation and industry standards in place at that time for compliance; and that if any non-conformities are identified these would require rectification or replacement prior to the introduction of hydrogen. MOB gas network systems that do not meet the recognised standard will not be suitable for repurposing. Issues such as the suitability of repair methods and the jointing methodology employed in each property require further consideration.

The diversity of the MOB population and system configuration means that HSE cannot draw further disaggregated conclusions on the suitability of broad MOB categories for hydrogen conversion. As recognised by the gas network industry, site-specific assessment would be required. The section on the MOB risk assessment provides further analysis on risk calculation.

Collaborative work between the gas and housing industries would be required to ensure compliance with both building and gas safety legislation.

A methodology underpinning inspection against a recognised standard detailing elements such as system design, location, material properties, operational parameters, maintenance, inspection, leakage history etc. would need to be developed.

HSE considers that development of an appropriate pressure testing regime for existing network systems has not been achieved. Further, the use of pressure testing alone as an indicator of the condition of the upstream network would not be accepted. Compliance with the relevant standard at the time will be required. Further consideration by the gas network industry would be required on how this would be demonstrated.

Section 10.3 Industrial and Commercial

Overall, HSE considers that it has been presented with limited evidence in relation to the use of hydrogen for heating in industrial and commercial settings. This evidence cannot be extrapolated to draw general conclusions across the diverse range of industrial and commercial settings at a national level. Any future roll out would require site-specific risk assessment, drawing on relevant standards and guidance

This conclusion only applies to the repurposing of natural gas to hydrogen for heating within existing industrial or commercial premises. This assessment has not considered current or future wider industrial applications of hydrogen beyond hydrogen for heating.

Introduction to Industrial and Commercial

In addition to domestic settings, industrial and commercial premises are also in scope for this evidence assessment. Many small-scale commercial premises such as small retail shops, hairdressers, doctor's surgeries and cafés currently only use natural gas in appliances either as a means to heat the space and/or for cooking. Since these businesses will likely use similar systems to domestic properties, they are not considered to be in scope as part of the industrial and commercial landscape.

Commercial properties that are in scope include larger and more complex properties that may currently use natural gas in catering/commercial appliances for heating and cooking. Examples of these businesses include hotels, restaurants, large office buildings, supermarkets and leisure centres etc.

Industrial premises include those that currently use natural gas as part of their processes and/or manufacturing regimes. These businesses may also currently use natural gas for onsite cafes and heating systems. All of these systems are in scope for this evidence assessment.

HSE's evidence assessment

Industrial Site Surveys and the Industrial Pathfinder Surveys

Evidence was presented to consider the impact on industrial end users from switching from natural gas to hydrogen. To understand the impacts, seven volunteer industrial sites were included in a series of site surveys that examined infrastructure onsite that could be included in conversion to hydrogen. The final set of sites were

selected to ensure that a broad cross-section of industry was represented that included a range of sectors, company sizes, locations, and different types of end use activity. The objectives of each site survey were to identify and assess the following: Technical, Safety, Cost, Environmental, and Implementation considerations. HSE has considered the evidence relating to safety.

Since each survey was site-specific, a summary report was submitted that aimed to identify common challenges across industry. It also examined if the demonstrations were sufficient and if further safety evidence was required.

The submission identified a number of areas that require further demonstration. The conclusions from the report are outlined below.

The site surveys report recommended updates to all DSEAR and Hazardous Area Classification documentation for industrial sites to account for the change to hydrogen. This is largely due to the different substance properties and behaviour leading to an increase in potentially hazardous areas.

For most cases in the site surveys, enclosures and buildings do not meet the requirements in DSEAR and IGEM/SR/25 for conversion to hydrogen due to inadequate ventilation. Despite this, the surveys suggest that only minor modifications are necessary to increase the ventilation to the required standards. Since hydrogen is a buoyant gas, ventilation will be required at height to prevent buildup of flammable volumes in roof spaces. The site surveys summary report recommended that industry do further work to determine the specific ventilation requirements for end users and to review the requirements for standard gas metering enclosures.

The site surveys report recommended the replacement of onsite gas detectors with equipment that has been specifically calibrated for hydrogen. Further work may be required by the sites to determine the best place to locate the detectors due to the buoyant behaviour of hydrogen. The site surveys recommended the installation of hydrogen leak detectors at metering stations, pressure let-down stations and end users.

The site surveys report states that demonstrating ALARP will be one of the key requirements for conversion to hydrogen. For other substances, this can normally be achieved by following Relevant Good Practice (RGP) guidelines. However, RGP is not yet available for design, construction and operation of hydrogen combustion equipment and as such, there will be a reliance on referring to lessons learned and the experience of current hydrogen users where relevant. The conclusions go on to state that site procedures will need to be updated, and staff trained accordingly for hydrogen hazards e.g. such as clear burning flames, increased flammability and higher volumetric flows etc.

The conclusions state that re-routing of existing natural gas lines should be considered because they may not follow good practice for hydrogen. For example, the report recommends routing that avoids areas of congestion in hazardous areas.

There are a number of common themes within the site surveys report relating to suitability of equipment. The site surveys report concludes that the gas pipework material metallurgy was assessed as being suitable for hydrogen service but noted that the records were insufficient to identify all materials. No recommendations were presented to address this issue. Furthermore, it is common for sites using natural gas to employ multiple threaded pipe fittings and it is unlikely that these will be suitable for hydrogen. If this is the case, then replacement may be necessary. The conclusions also state that burners and burner management systems will need to be reviewed and updated. This is to capture that hydrogen burners will have different requirements in terms of e.g. combustion air flow, purge cycles and flame detection etc. than natural gas.

The site surveys summary report noted that consultation with the Original Equipment Manufacturers (OEMs) indicated that for burners, both new and retrofitted, further work is recommended to understand and determine how nitrogen oxides (NOx) emissions can be managed safely.

HSE notes the development of the Hydrogen Enabling Standard – non-domestic, IGEM H3 to support potential roll out of 100% hydrogen heating to non-domestic settings.

Automatic Isolation Valves

Automatic Isolation Valve (AIV) systems are safety features commonly found in commercial and industrial premises that use natural gas. Evidence submitted by the gas network industry examined their applicability in small commercial installations using hydrogen.

The report¹⁰¹ recommended that gas installation pipework should be located outside for industrial and commercial business where it is reasonably practicable. This will prevent hydrogen accumulating and creating flammable atmospheres in roof spaces and other voids. However, HSE notes that this may introduce other hazards, and it would be appropriate to review all hazardous area classification documentation with IGEM/SR/25 in mind for each site.

Three commercial AIVs were tested and found to be suitable for use with hydrogen. For larger commercial units, de-stratification fans are often used to prevent build-up of flammable atmospheres. However, the effect of these fans was not included in this project which means that movement of gas, how the hydrogen builds up and how

101 Use of Automatic Isolation Valve (AIV) Systems with Hydrogen – Final Report, Cadent, 2023

effective detection methods are, is not clear. The report recommends further work in this area.

HSE did not have any significant issues with the evidence supplied as part of this project.

Hydrogen ready equipment

The site surveys identified that, while some existing equipment is suitable for use with hydrogen (e.g. burners and flare pilots) or can be modified relatively easily, there is also some equipment that has no hydrogen ready equivalent that is commercially available (e.g. direct fired space heaters and gas fired torches). This means that there are some sites that cannot be converted to hydrogen until hydrogen ready equipment is available or alternatives found. Where major modifications to equipment were identified, it was usually in relation to the requirement for larger diameter pipework because the current system would not provide the same energy flow when converted to hydrogen.

Conclusions

The industrial site surveys provide the main body of evidence in relation to industrial and commercial settings. The conclusions and recommendations of the report cover all aspects of the conversion to hydrogen.

HSE would expect sites to have competently trained staff that understand the hazards associated with hydrogen and are able to operate equipment onsite in a safe and appropriate manner. Some of the recommendations relate to upskilling and improving Relevant Good Practice and procedures. Others relate more to safe practices such as adequate ventilation and using materials that are appropriate for use with hydrogen. Overall, HSE would expect sufficient evidence to show that it is feasible for sites to implement an appropriate risk assessment for industrial and commercial settings and that ALARP is met.

Overall, HSE does not disagree with any of the conclusions and recommendations listed in the site survey report.

While the industrial site surveys give a useful overview of the issues that a typical site would experience during conversion to hydrogen, the surveys are based on a very small sample set of seven example sites. This is not considered to be enough to give a realistic overview of industry throughout the GB as a whole and it is very likely that some areas have been completely missed. While the site surveys give a useful indication, it is likely that conversion to hydrogen will need to be considered on a case-by-case basis for industrial and commercial settings. For example, the site surveys report states that some sites are not fully aware of the materials they have onsite and how they may interact with hydrogen. This is one area that may need to be resolved on a case-by-case basis.

Although there is currently a significant amount of industrial experience on the usage of hydrogen, there is the expectation that this knowledge can easily be applied to hydrogen conversion. However, not all experience and competence will translate well. Sites should consider if upskilling is required to ensure staff know how to use new and retrofitted kit and to make sure any new hazards and new consequences are understood. One aspect to consider is the lack of evidence to show that human factors in this area have been considered.

When the evidence is considered as a whole, it is important to note:

- The research into the phenomenon of air ingress has not yet been conducted in relation to industrial and commercial settings. This represents a very significant evidence gap which constrains HSE's ability to determine the feasibility of converting these settings for use with hydrogen. Significant further work in this area would be required.
- The GB QRA includes a supermarket, entertainment venue and an office as examples of commercial businesses. These are only a few examples and cannot be considered representative of all commercial businesses. The nuances of standalone commercial businesses and how they may be adapted for hydrogen individually has not been considered. The GB QRA does not include industrial settings – it is likely that industrial QRA will be required on a case-by-case basis.
- There is a wide range of commercial and industrial infrastructure that cannot be grouped together easily for the purposes of Relevant Good Practice. This introduces a risk that bespoke solutions may be developed where common approaches and learnings should be applied.
- Duty holders would also need to consider if their operations would require Hazardous Substances Consents (HSC) or be subject to COMAH if they were operating with hydrogen in sufficient quantities.
- In general, where modifications were required for existing equipment, no specific details of what the modification for hydrogen would entail was provided. This will likely be required on a case-by-case basis.
- The submissions did not demonstrate if some of the findings and recommendations for all domestic based evidence can be transposed to an industrial or commercial setting.

Overall, HSE considers that it has been presented with limited evidence in relation to the use of hydrogen for heating in industrial and commercial settings. This evidence cannot be extrapolated to draw general conclusions across the diverse range of industrial and commercial settings at a national level. Any future roll out would require site-specific risk assessment drawing on relevant standards and guidance

This conclusion only applies to the repurposing of natural gas to hydrogen for heating within existing industrial or commercial premises. This assessment has not

considered current or future wider industrial applications of hydrogen beyond hydrogen for heating.

Section 11. Risk Assessment

The QRA has sought to make a comparison between the risks from natural gas in 2032 and the use of 100% hydrogen from 2032 onwards. HSE considers that a direct like for like comparison is inherently challenging and comes with limitations on the level of confidence that can be applied to it. The risks associated with the live operation of the natural gas system comes with a long historical record, compared to the desk top modelling applied for the hydrogen risk assessment. This is an unavoidable constraint when dealing with a proposal for a new technology.

The QRA modelling demonstrates that all planned risk reduction measures could, on average, reduce the risks from a hydrogen system to slightly above those from natural gas. Additional risk reduction measures will be required to lower the risks further. The QRA provides examples of the further risk reduction measures that would be considered. Site-specific risk assessment would then inform when these additional mitigation measures would be deployed.

While the evidence suggests that the average risk of fatality could be managed to the level of natural gas, evidence points to the potential for greater damage to arise from incidents involving 100% hydrogen.

Overall, the QRA model forms the basis for an input into a future ALARP demonstration. However, HSE still has some concerns regarding the inputs to the QRA model which could lead to different risk estimates, which could influence the consideration of appropriate risk reduction measures.

Introduction to Risk Assessment

Risk assessment is a process that is used to understand and to control the risks, where possible, that people may encounter whilst they undertake an activity. It consists of identifying hazards, estimating the consequences and likelihood from each hazard, i.e. the risk, and then identifying measures that can be taken to reduce the risk. Risk assessment is not an exact science and can only provide an approximate idea of the risks involved, however detailed the analysis that is undertaken. Often, the more detailed the analysis, the more uncertainty there is in the results obtained due to the number of assumptions and approximations that have to be made. Given the uncertainty of quantifying the risks associated with any novel technology/use, a degree of conservatism should be applied to the assumptions used.

Quantitative Risk Assessment (QRA) uses statistical and numerical methods to calculate estimates of risks, their impacts, and probabilities. A QRA can be used to inform a decision, but the results should not be taken as absolute, precise measures of the risks that people can be exposed to.

The GB QRA (hereafter referred to as the QRA) for 100% hydrogen heating presents an evaluation of the risks associated with fires and explosions, carbon monoxide poisoning and exposure to unburnt gases from the gas distribution system.

The QRA has been undertaken by DNV in partnership with the gas network industry. For this report, the distribution system includes the gas distribution network upstream of the ECV and gas use within properties downstream of the ECV. The use of hydrogen for both cooking and heating has been considered. The aim of the QRA is stated as being to assess the risks posed by a system repurposed for hydrogen usage, and to assess the benefits of risk mitigation measures.

The QRA covers gas distribution across Great Britain, including governors, mains and services operating at 7 barg and below, as well as end user use in customer properties. The QRA covers both domestic and non-domestic properties. Industrial settings are not considered. MOBs are represented but are based on a separate study using a consistent methodology with the details contained in a separate report. The MOBs QRA is discussed in Section 13.

The QRA consists of a methodology report and a results report. The methodology report details the methods used, the assumptions made and the data inputs to calculate the risk. The results report presents the results of using the methodology for gas use within properties downstream of the ECV, together with combined results that cover aspects of the distribution network.

In addition to domestic premises, the QRA includes a supermarket, entertainment venue and an office as examples of commercial businesses. The QRA methodology report states that the following assets are not included in the assessment:

- Any form of natural gas or hydrogen production.
- Any form of natural gas storage.
- Any gas infrastructure operating at more than 7 barg.
- Industrial gas users that store significant quantities of gas, or that use gas in their processes (as opposed to purely for heating buildings or cooking).
- Compressed natural gas filling stations, and hydrogen vehicle refuelling stations.

The QRA provides measures of both individual and societal risk. Individual risk is an estimation of the risk that a hypothetical person could be exposed to from a particular hazard. The level of harm that is being measured needs to be stated and, in the QRA, this is the risk of death.

Societal risk considers incidents where multiple fatalities can occur. There is an aspect of reflecting the greater societal concerns that arise from larger events where many people are harmed. In any risk assessment the level of harm that is being measured needs to be specified and in the QRA, the risk of major and minor injuries has been considered, as well as the risk of death. A societal risk calculation is a combination of the likelihood of an event occurring and the number of people who can be harmed from that event.

Key inputs to the QRA include supporting evidence provided on ignition consequences, helium dispersion, proposed mitigation measures, cast iron, hazardous area mitigation and air ingress, including the results from numerous experiments looking at different aspects of the consequences of a hydrogen release. In addition, the QRA methodology has been used as the basis for other evidence that has been submitted i.e. the QRA mitigations report and the MOB's QRA, with the results from these reports feeding back into the QRA results report¹⁰². The National Hydrogen Safety Assessment (NHSA), which is discussed later, also references the QRA.

HSE's evidence assessment

QRA Methodology Report

HSE has reviewed the Great Britain Distribution QRA Methodology Updates in CONIFER report¹⁰³ and has made the following comments and observations:

It has been assumed that the cast iron failure rates will not change significantly under hydrogen service, which contradicts studies showing that hydrogen has significant impact on material properties. It is stated that a sensitivity study has been undertaken to address this issue, but this was after the submission of the QRA. Additional evidence has been seen by HSE in the interim, although it is not clear if it is the study referred to in the QRA methodology report. HSE's view on the suitability of cast iron pipes for use with hydrogen has been discussed elsewhere in this document and will not be repeated here. It was concluded by HSE and the IGEM review panel within evidence submission Cast Iron Technical Review Group of Cast Iron Materials etc, that DNV's contention that there is no discernible increase in the failure frequency of iron mains, had not been fully demonstrated. HSE does not expect an increase in failure frequency due to hydrogen use alone but the expected failure frequency for iron mains for both natural gas and hydrogen is higher than for the rest of the distribution system.

¹⁰² Great Britain Distribution QRA Risk Predictions, DNV, 2024

¹⁰³ Great Britain Distribution QRA Methodology Updates in CONIFER, DNV, 2024

Comments have also been made on some of the supporting evidence, which will directly affect HSE's view of the QRA methodology. These are discussed subsequently.

Hazardous area mitigation

The hazardous areas impact mitigations report ENA_564_1_NIA2_SGN0051_HAIM Phase 2_379 HAIM Stage 2a report v2.0¹⁰⁴ aimed to investigate the behaviour of hydrogen through larger vents, and to compare the results to IGEM/SR/25. An earlier phase of the work had looked at smaller scale releases and found a disparity between hazardous zones measured during testing and those predicted by IGEM/SR/25.

The Stage 2 work consisted of a number of experiments, which looked at hydrogen plumes from 15 mm and 50 mm vent pipes.

HSE has noted that the results from these tests appear to indicate that hydrogen did not ignite until it reached approximately 11% concentration. This is considerably higher than the 4% Lower Flammable Limit (LFL) that is generally used in risk calculations. These releases were performed outdoors. No tests were undertaken indoors. If this were to be tested and similar concentrations were observed for ignition this could imply that the assumptions made in the QRA are suitably cautious. However, as this evidence was not provided, uncertainty remains over these assumptions.

Ignition consequences

The Ignition Consequences Report presents experimental research that consisted of three phases and explored the severity of explosions based on domestic structures. The evidence does not state if the results will be applicable to industrial and commercial settings.

This project consisted of a number of experiments researching the various phenomena contributing to the severity of explosions in domestic structures. In particular, it has looked at build-up, confinement and congestion effects. It has also considered multi-rooms and detonation initiation and combinations of various different factors e.g. congestion and build-up effects. The potential consequences that would have been experienced in a domestic setting have also been assessed.

The experiments have identified particular aspects of hydrogen releases that need to be controlled, as well as providing a dataset for validating models.

The work has made a number of findings. These are:

¹⁰⁴ Hazardous Area Impact Mitigations (HAIM) Phase 2A: Full scale testing Interim Report, Steer Energy, 2024

- More severe effects were seen for hydrogen once it had reached a concentration of 15% within a room, when compared to natural gas. At concentrations of 30% by volume, some of the experiments resulted in a deflagration to detonation transition i.e. a fire progresses to an explosion.
- When a leak occurs, the gases in the room become stratified with hydrogen rising to the ceiling and forming a hydrogen gas layer. The height of the gas layer affected the overpressure generated.
- The effects of confinement were worse for hydrogen than natural gas at concentrations of 15% by volume, meaning higher overpressures were generated. At 12%, the overpressures were lower than for the worse case natural gas concentrations i.e. for the natural gas scenarios at which the greatest overpressures were observed.
- When considering congestion, at 15% by volume concentration, the overpressure effects for hydrogen were generally less than for natural gas at a worse case concentration.
- Detonation was a possibility in domestic settings at concentrations of 30% by volume hydrogen in air.
- Structural collapse of buildings on the opposite side of the street was possible with hydrogen concentrations above 20% by volume.
- Limiting concentrations to 12% by volume should mean that explosions are no worse than for natural gas at worse case concentrations.
- Engineering controls and procedures should target ensuring that higher hydrogen concentrations are not possible to achieve.

The work on ignition consequences is directly relevant to the QRA, although only the results of Phase 1 were available at the time of writing the QRA. The networks have stated that subsequent work has been undertaken to investigate all of the results of the ignition consequences work. These investigations have reported that the model used in the QRA is potentially cautious when considering the relative risk of explosions between hydrogen and natural gas. This work has been captured in a separate report associated with the ignition consequence work (*Update to Confined Explosion Modelling*, DNV report 10474440-4, September 2024¹⁰⁵).

HSE has made one observation, which is detailed below:

- The explosion model has been updated based on the output of the experiments, noting that the updated version is not the one used in the QRA. The explosion modelling report states that the PLL predictions in the updated model are too high when compared to historic data and that one way to address this would be to slightly reduce the ignition probability. If the

105 Confined Explosion Modelling, DNV, 2024

model is used to update the QRA in the future, it will be necessary to ensure that this modification is in place.

In addition, the report states that emphasis should be put on designing out scenarios with high numbers of fatalities.

Although the work has provided some increased understanding of hydrogen explosions, together with providing a dataset to improve model accuracy, the work has only looked at the effects of ignition in residential properties. There remain uncertainties and unknowns when considering commercial and industrial sites.

Helium dispersion tests

The helium dispersion tests¹⁰⁶ aimed to show how a significantly lighter than air gas will move around a range of real domestic properties in the event of an internal gas escape. The tests have been linked to ignition consequence work to show the effects of risk mitigation measures such as ventilation and hydrogen detectors.

The evidence submission evaluated the effectiveness of mitigation measures in reducing the risk of hydrogen ignitions. It found that the greatest hazards occur with ignitions of high concentrations of hydrogen. At concentrations above 16%, the consequences of hydrogen ignition are greater than those for natural gas. At 20%, they are much greater. These tests have enabled the gas network industry to propose a number of recommendations including the use of two EFVs, one mechanical and one in the SMART meter, preferred locations for meters, etc.

The helium dispersion tests have addressed many of the questions around how hydrogen will disperse in a domestic setting, but there are a number of outstanding questions. In particular, most of the releases under the conditions tested stratified, with the highest concentrations seen at the ceiling. The greater the height at which the release occurred, the higher the concentration at the ceiling, with higher concentrations leading to potentially more damaging consequences. Only limited higher level releases were tested for some of the medium release rates and none for the lowest release rate. It is therefore unclear to HSE whether the most damaging concentrations could occur at the ceiling with some of the lower release rates if they are released at height. More tests would be required to provide assurance that some of the lower release rates, if released at 1.5 m, could not result in significant high-level concentrations. The gas network industry has indicated that they will conduct further work to address this evidence gap.

It is stated in the QRA that the majority of the information from this project has been included in the model development and risk calculations undertaken. The networks have confirmed that the results of the tests that have not been included in the model

¹⁰⁶ Dispersion of Helium Releases in Domestic Properties, KIWA Energy, 2024

used for the QRA. These would be added at a later date for use in future iterations of the QRA.

HSE considers that the demonstrations have taken the gas network industry a long way towards understanding the consequences of hydrogen releases and ignition. However, there is still an element of uncertainty around how hydrogen will disperse within a building. Conclusions from future QRA modelling may therefore differ from those presented here.

Suitability of iron

The assessment of the suitability of cast iron has been addressed in the preceding chapters on the LTS and LDS. However, aspects of the Iron Mains and Fittings in Hydrogen Service report are relevant to the discussion of the suitability of the QRA methodology for assessing the risks from a hydrogen system, including informing the assumptions made within the QRA.

Following the review of the evidence submission Effect of 100% hydrogen on cast iron assets there remain concerns including:

- Statements on Gas in Building incidents, due to joint leakage from cast and spun iron mains, are contradictory but an increased level of risk is predicted. The rate of escape from a typical joint leak is said to be too low for gas to accumulate within a property and reach a flammable concentration. Conversely, the submission indicates that, for the Greater Manchester area, the total predicted risk with hydrogen will increase by 7.2%, with joint failures contributing to a greater increase in incidents than corrosion incidents.
- The effects of higher operating pressures (in hydrogen duty) on joint failure risk are not fully explained. The submission indicates that a series of “initial scoping calculations” were performed for a sample of mains, and it was found that the conclusions are not significantly affected by the operating pressures modelled, but the sample size is not detailed, and example calculations are not provided.
- The total Risk of Incident data presented for cast iron is based upon an ‘approximately representative’ area of the network (in the Greater Manchester Area), however, no statistical analysis to that effect has been undertaken. As such, the figures may be higher in other areas (e.g., due to a higher corrosion risk), therefore site or area-specific risk calculations are likely to be required prior to hydrogen introduction. The recommendations in the main report include not replacing large cast iron pipes (greater than 8” diameter), within 30 m of buildings, “unless otherwise justified to do so, because they have Broadly Acceptable level risks”. However, the site or

area-specific risk calculations referenced above could potentially shift risk levels to the ALARP range, in some cases.

- The Hydrogen in Iron report acknowledges that the Location Specific Risk is up to 10 times higher with hydrogen than with natural gas, but states that this risk falls within the 'broadly acceptable' range. This conclusion does not negate the requirement to investigate further risk reduction measures or periodically review ALARP considerations. Predicted increases in the level of individual risk of death (from a hydrogen gas explosion in comparison to natural gas) are provided.
- Due to calculated risk levels, the 30 m gas main proximity limit (to properties) will substantially be retained for 100% hydrogen cast iron pipes (unless individual pipe, or site-specific, risk assessment dictates otherwise). The gas network industry has indicated that they would intend to replace all iron pipes within 30 m where the individual risk of fatality (in hydrogen duty) is greater than one in one million per annum, before hydrogen is conveyed in the impacted pipes. In the North-West, this is expected to require an additional 43.44 km of main to be replaced. National cast iron main replacement figures, based on the results of the QRA risk assessment tool, remain unknown, although estimated at 360km.
- The submission indicates that not all hazards or potential release scenarios for hydrogen are considered within the risk calculations. Other possible release scenarios can be envisaged. The safety case associated with each leak scenario encountered within the UK network may differ due to its specific location, characteristics of gas release or basis of safety etc. As such, any distance correction may also vary between each leak scenario.

There is a lack of clarity in the report over the calculation of individual risk. HSE understands that the individual risk of fatality has been calculated from the output of the Mains Replacement Prioritisation Scheme (MRPS) model using the same methodology as has been used previously for natural gas in the Iron Mains Risk Reduction Programme (IMRRP). HSE has a number of significant concerns about this methodology when used to calculate absolute risk for hydrogen. In particular:

- Individual risk is shared across multiple people in multiple buildings. This means that the individual risk for each person is potentially artificially lower than it should be.
- Cumulative risk from multiple pipes is not considered. The individual risk of fatality posed by a specific pipe may be broadly acceptable, but when

combined with the risk posed by other pipes in the vicinity, the cumulative risk may not be broadly acceptable.

- The natural gas and hydrogen analyses appear to have used different assumptions about the number of fatalities per explosion. There is a possibility that the assumed number of fatalities per explosion is too low in the hydrogen analysis.

Modifying the individual risk calculations to address the concerns above would lead to an increase in the individual risk of fatality.

Further considerations are described below:

- In the hydrogen analysis, modifiers have been applied to the predicted natural gas failure frequencies for fractures of cast and spun iron pipes, but not for ductile iron failures or for other cast and spun iron failure modes. This would appear to imply that hydrogen embrittlement is not considered for ductile iron or for other failure modes. In addition, no justification is provided for the values of the modifiers used and no confidence limits have been provided. The confidence limits would indicate what level of certainty there is in the values used.
- Modifying factors have been applied to other aspects of the calculations undertaken to determine the risk from iron mains. The basis for these factors has not always been provided and it is not clear how the properties of hydrogen, e.g. its flammability range, have been used to derive them.
- There are statements saying that the location specific risk with hydrogen is up to 10 times higher than with natural gas, but it is still within the “broadly acceptable” region. A risk has not automatically been reduced to ALARP if the modelling suggests that it is within the “broadly acceptable” region. This is particularly the case when using experimental data to support the risk assessment of a new technology, where no historic data exists and hence there is greater uncertainty in the results of the modelling. There is still a necessity to review and determine if there are any additional measures that are reasonably practicable to apply, recognising that the definition of “practicable” is less onerous at this level of risk. This would particularly apply in this scenario as the risks are an order of magnitude higher than the risks posed by the existing natural gas system.
- The work seems to primarily rely on the results of risk assessment. A QRA should form part of the reasoning as to why additional work should or should not be done, but other considerations should also form part of the arguments e.g. materials issues, industry good practice, etc.

- It is recognised that site-specific risk assessments are likely to be required as the risks will vary across different parts of the network. There will therefore need to be consistency between QRAs. The use of different assumptions and/or models for site-specific QRAs could lead to inconsistent conclusions being drawn.
- As noted in the issues above, it is not clear that all causes of failure have been considered e.g. hydrogen embrittlement in ductile iron had not been considered. This leads to a lack of confidence that all potential release scenarios due to degradation and other factors have been adequately considered and hence that all possible sources of risk have been modelled. If some scenarios have been missed, then it is likely that the risks from remaining iron mains have been underestimated. This would affect the results from all QRAs that rely on the outputs of this work.
- It is worth noting that the QRA mitigations report, which is discussed later in this document, recognises that there is likely to be a need to replace some additional iron mains beyond those that are already planned to be replaced by the end of 2032.

Air ingress

The possibility of air ingress into downstream hydrogen assets during periods when the system is isolated and not operating at pressure has been discussed in HSE's evidence assessment for Downstream in Section 10.1

In addition to the concerns raised in that section, there are potential limitations associated with the QRA. As the specifics have already been discussed, the QRA issues can be summarised as whether or not the proposed mitigation measures have been fully assessed, whether it will be assumed in the QRA that these measures will be implemented throughout the downstream gas system and concerns that the work has only considered domestic housing. Further work is suggested in the report to investigate the possibility of air ingress in MOB's and non-domestic buildings, along with the durability of EFVs and gas meters. The approach taken in the report, however, does not appear to be unreasonable.

The version of the QRA that has been assessed by HSE does not make any assumptions with regards to air ingress and it is therefore not possible to say how robust the conclusions are in light of this additional piece of work.

Elevated pressure test

An elevated pressure test at 1 barg had been proposed for downstream gas systems, prior to the conversion to hydrogen. It has been found that this has the potential to

identify leaks that would not be apparent at lower pressures. There are arguments, however, that the test itself could increase the likelihood of the pipework failing and could cause additional problems if appliances connected to the pipework have not been correctly isolated prior to the test. These potential weaknesses should be identified if the failures occur during the test, but the test could lead to weakening of the pipework leading to failure at a later date. Currently IGEM Enabling Standard H2 requires a pressure strength test between at 82.5 mbarg and 85 mbarg. Further data is required on the topic to try and gain an understanding of how many leaks are likely to be identified by an elevated pressure test and the scale of any adverse effects that the test could cause.

In the case where an elevated pressure test is not applied, there must be suitable means applied to ensure adequate pipework integrity, particularly with regards to any identified construction defects.

QRA Results

The GB QRA Risk Predictions report presents the results of running the methodology detailed in the QRA methodology report. The data used to undertake the calculations includes:

- Numbers of governors in operation.
- Lengths and types of mains in operation.
- Numbers and types of services in operation.
- Numbers and types of gas customers receiving natural gas, including houses, flats in multi-occupancy buildings, and non-domestic buildings.
- Details of building sizes, occupancy patterns and potential gas leak sources.

The QRA methodology has been used to calculate a baseline 2032 natural gas risk level to compare the hydrogen scenarios to. For the hydrogen base case it is assumed that the following are implemented:

- The planned metallic main and service replacement.
- Further improvements to appliances.
- Changes in operating pressures on the network.
- Two EFVs in the meter installation in houses and flats, but not in non-domestic buildings.
- Inspection of pipework downstream of the ECV before hydrogen is introduced.

In the report both individual and societal risk have been considered. For societal risk the general measure that has been used is Potential Loss of Life (PLL) although some FN curves are also given, where F represents the frequency of at least N casualties occurring per year.

The report states that it is possible to operate a hydrogen distribution system at a similar level of risk to the equivalent natural gas system, using safety mitigation measures that are deemed to be practicable. Without these measures (outlined above) then the societal risk calculations indicate that there will be increased risk to the public from hydrogen usage.

The QRA has considered additional safety features to lower the risk further. The planned set of additional mitigation measures to ensure the risk is no higher than natural gas is:

- Additional ventilation in governor kiosks.
- Gas detectors in all building types that raise a local alarm and notify a control centre of the presence of gas.

It is suggested in the QRA that the deployment of these additional mitigations can reduce the risks to ALARP.

The QRA considers failure of these mitigation measures to operate, either due to a failure of the device itself or due to it not being fitted correctly. This is accounted for in the calculations.

The results of the QRA indicate that the overall societal risk level from the hydrogen distribution network, using “planned” mitigation measures, is 8% higher than for a natural gas network (i.e. 1.08 times the natural gas value). This, in risk terms, is a small difference as the actual numbers are very small. An 8% increase on a very small number represents a very small absolute increase. Note that this is the hydrogen base case with the two additional measures listed above. Additional mitigations are therefore proposed on a site-by-site basis.

The information provided above is generic in nature, but the QRA goes on to consider the risks from each type of building separately. A summary of this information follows.

Risk from hydrogen use in houses

If the hydrogen base case is compared to the natural gas base case for houses, then the Potential Loss of Life (PLL) is found to be 2.6 times higher for hydrogen. The most significant increases in risk are from mains and services. In the case of the mains, the societal risk is dominated by explosions and by leaks from low pressure mains. Iron mains make up just 4.3% of the total population by length but account for approximately 41% of the total risk posed to houses by hydrogen.

An analysis has also been undertaken looking specifically at explosion events from houses that have hydrogen purely for heating i.e. a boiler only. This analysis shows that the individual risk increase is greatest for terraced houses; approximately a 3 times increase in the individual risk. Semi-detached houses see an increase of

approximately 2.4 and detached houses of just under 2. It should be noted that this is for one particular type of scenario only, is assuming the base case for hydrogen i.e. not the “planned” case with additional mitigation measures, and the individual risk is still low, the highest value being approximately 9×10^{-9} per year.

Different components of the individual risk have been compared for terraced and detached houses for the natural gas and hydrogen base cases, due to leaks downstream of the ECV. Essentially, a high risk and a low-risk case have been considered where the high risk is for a terraced house with a boiler, three cooking appliances, a fireplace and an internal meter. The low-risk scenario is a detached house with a boiler and an external meter. The largest increases in individual risk for the terraced house scenario are from the meter and cooking appliances. For the detached house scenario, the main increase is from pipework. The individual risk is approximately four times higher for the terraced house (approximately 7×10^{-8} per year) than the detached house (approximately 1.7×10^{-8} per year).

If components upstream of the ECV are considered, then the individual risk for someone in a terraced house is approximately an order of magnitude higher with hydrogen than for natural gas. This is largely driven by the risk from the main and leads to an individual risk greater than 1×10^{-6} per year.

It should be noted that the values quoted above are without the additional mitigation measures proposed for the “planned” hydrogen scenario but provide support for why they are needed.

Risks from hydrogen use in MOBs

The QRA Results report details the results from assessing the risks posed to people by the use of hydrogen in MOBs. There is also a separate MOBs QRA, which will be discussed later in this document. It is not entirely clear whether the MOBs QRA supersedes the information provided in the GB QRA report and so a summary of the information contained within the results report is provided below.

For the MOBs, the risks posed by mains in hydrogen usage is potentially more than an order of magnitude higher than for natural gas for those buildings with four or fewer storeys (up to 25 times higher). The risks appear to reduce as the number of storeys increases and is dominated by explosions. Although iron mains make up 4.3% of the population by length, they represent just under 40% of the total risk posed to MOBs for hydrogen operation.

Very similar results are seen when considering the risks from services, including a risk of fatality up to 25 times higher for hydrogen than natural gas.

Overall, the societal risk from using hydrogen in MOBs is dominated by risks from meters, risers and laterals, and the societal risk generally decreases as the number of storeys increases, up to eight storeys. Above this number, the risk starts to

increase again. In all cases, without additional mitigation measures, the societal risks from hydrogen usage are significantly higher than for natural gas.

From an individual risk perspective, the risk increases as the number of storeys increase. This contradiction with societal risk reflects the far larger number of low-rise MOB's throughout the country. The individual risk in the hydrogen case is dominated by releases from the risers and laterals, with meters providing the next largest component. These contributions are reversed in the natural gas case.

As noted in the evidence assessment for MOB's, the MOB's surveys report showed significant non-compliances with standards across the small number of buildings surveyed. It will be necessary to ensure that all MOB's are compliant prior to conversion. This could impact on the MOB's QRA, and the results reported here, as the failure rates for risers were taken from network data, which will include all the non-compliant systems. The effect of ensuring compliance should be to reduce failure frequencies and hence risk.

Risks from hydrogen in non-domestic buildings

The results of considering hydrogen in non-domestic buildings indicate that the societal risks posed by mains is approximately an order of magnitude higher for hydrogen than for natural gas. The largest contributors to the risk appear to be open cut PE and cast-iron mains. The societal risk from mains is dominated by explosions and by low pressure mains. As was the case for MOB's and houses, iron mains make up 4.3% of the total population by length but they represent about 41% of the total risk posed to non-domestic buildings when in hydrogen use.

The societal risks from services for non-domestic buildings are approximately doubled when comparing hydrogen to natural gas. The risks are dominated by open cut PE, and explosions represent approximately 1/3 of the risks from services.

When considering leaks from the meter or downstream of the ECV in non-domestic buildings, the dominant effect is from pipework. Overall, the societal risks from this part of the system are approximately four times higher for hydrogen than natural gas.

Summary of risks for all building types

When all building types are considered, the societal risks from the hydrogen base case compared to the natural gas base case are approximately 2.6 times higher than the natural gas risks. There are three main contributions to the risk in the hydrogen case; end use, services and mains, with each contributing approximately equal amounts to the overall total (the societal risks from services are slightly lower than from end use and mains).

The introduction of the additional mitigation measures in the "planned" hydrogen case reduce the risks from all the main contributors to the extent that the societal risk, as measured by the PLL, is 1.08 times higher than the natural gas base case.

Additional mitigation measures

In addition to the mitigation measures already identified, the QRA discusses further measures that could be implemented. The additional risk mitigation measures that the gas distribution network industry have concluded would be effective, at least in some locations, include:

- Replacement of metallic services for all building types.
- Installation of EFVs in non-domestic buildings.
- Installation of EFVs at the upstream end of services, for all building types.
- Installation of gas detectors with the ability to close an Automatic Isolation Valve (AIV) to cut off the gas supply to the building, or part of a building.
- Increased ventilation to external locations in rooms where gas releases are credible.
- Relocation of internal meters to external locations.
- Conversion of some large buildings or MOBs to use energy centres rather than gas distributed throughout the building.

It is asserted that combinations of these mitigation measures can reduce the risk from a hydrogen distribution system to below that forecast to be posed by natural gas in 2032.

The following have also been stated in the results report:

- With the planned risk mitigation measures in place, the frequency of incidents in buildings where the most severe events could occur is predicted to be approximately the same for hydrogen as currently experienced with natural gas.
- Risk mitigation measures that reduce the likelihood of fatality also reduce the likelihood of non-fatal injuries occurring. Therefore, the unambiguous measure of fatality risk can be used as a measure of effectiveness of different controls.

QRA recommendations

The QRA makes a number of recommendations. Firstly, there is a recommendation for the use of gas detectors in most buildings. It is stated that they should be developed “to be reliable and practical to use, ideally with functionality that does not rely on human action to report the presence of gas”. HSE notes that the QRA highlights the need for their functionality and reliability to be further developed and tested.

A second recommendation is that, for future safety assessments, three broad categories of non-domestic buildings could be used. These would be:

- “Simple buildings that have gas equipment similar to that of a domestic property, defined either by physical size or perhaps gas meter capacity. These are the small, medium and large generic buildings modelled in this QRA.
- More complex buildings or sites that use gas only for heating.
- More complex buildings or sites that use gas for heating and cooking.”

The final recommendation is to gather more data on MOB configurations to aid in decisions regarding the process of converting buildings to hydrogen.

The QRA results report recognises that the model used is likely to be updated as more information becomes available. This could, in turn, lead to changes to the results of the QRA modelling work.

Four further pieces of work are recommended to be carried out by the gas network industry in the QRA results report. These are:

- Investigation of the possibility of air ingress into hydrogen systems. Note that this is an area that is already under investigation.
- Ventilation arrangements in governor kiosks should be determined to limit the potential hydrogen/air concentrations to a tolerable level.
- The risks associated with alternative heating and cooking sources should be quantified e.g. the use of electrical appliances, to enable a more accurate comparison of risks to be made.
- Individual risk calculations should be undertaken for example properties to aid in the development of criteria for determining which risk mitigation measures are required for a particular building based on its characteristics and gas infrastructure.

Risks from Natural Gas

The QRA has sought to make a comparison between the risks from natural gas in 2032 and the use of 100% hydrogen from 2032 onwards.

HSE considers that a direct like for like comparison is inherently challenging and comes with limitations on the level of confidence that can be applied to it, including:

- That the risks associated with the live operation of the natural gas system comes with a long historical record, compared to the desk top modelling applied for the hydrogen risk assessment. This is an unavoidable constraint when dealing with a proposal for a new technology.
- That the nature of incidents may change between the risks associated with natural gas and 100% hydrogen. For example, the risks from carbon monoxide poisoning will be removed with hydrogen but the modelling on

ignition consequences point to the potential for greater damage to arise from explosions where the hydrogen concentration is above 16% in air. As such the perceptions of risk arising from fatal incidents may differ from those with natural gas.

The risk has been calculated using DNV's CONIFER model and has generally been presented in the form of PLL, rather than individual risk. Various aspects of the system have been considered separately e.g. mains, services, etc..., together with an overall PLL value for GB as a whole. The QRA has concluded that it is possible to reduce the risks from a hydrogen system to slightly below those from a natural gas system in 2032, with the addition of suitable risk reduction measures. These measures are in addition to those assumed in the "planned case", which was calculated to give a risk value that is 8% higher than for natural gas and it would be down to the GDNs to determine which ones are most suitable for their network.

HSE has reviewed the details of the model and the supporting evidence, with any concerns discussed previously in this document. In terms of the methodology, the approach used is detailed and comprehensive and is based on historical data from across the gas networks, as well as from the results of research that has been undertaken over the last few years. There are some concerns, however, regarding some of the inputs, particularly around iron mains, and inconsistencies between the results of the ignition probability work and the helium tests. These largely affect the inputs to the model, rather than the model itself, but they could lead to the risks being potentially underestimated in some circumstances.

In addition, there is a question around the level of spontaneous failures downstream of the ECV that has been assumed post-conversion. The networks have indicated that there would be some benefit in regular checks as this has been shown to reduce the number of failures that occur, but they have stated that only the initial check at conversion will be undertaken. This leads to a question of whether the number of spontaneous failures has been underestimated in the QRA.

Until the outstanding questions regarding the evidence that has been discussed in relation to the QRA have been resolved, then there remains some uncertainty over the final results obtained and the conclusions being drawn from it.

It should be considered, however, that the calculated risks are very low, and considerably lower than many everyday risks. Even if the calculated risks are increased, based on the outcome of ongoing work and HSE's comments, it is likely that the absolute values will remain low. It may then be possible to implement more of the additional measures that have been identified to ensure that the risk is again reduced to natural gas levels or below.

One point of note is that the risks being discussed here are average across GB or across a section of the gas system. It is therefore possible that some

locations/people could see their individual risks rise slightly when compared to natural gas. These are cases where additional mitigation measures may be expected to be applied.

It should also be noted that there is a separate report investigating the effectiveness of a number of different mitigation measures and determining which ones should be applied either universally or in specific scenarios. In contrast, the analysis undertaken in the QRA with the additional mitigation measures was to illustrate that it is possible to reduce the risks from a hydrogen network below those for natural gas, without recommending any particular package of measures beyond the “planned” case.

Conclusions

The QRA has sought to make a comparison between the risks from natural gas in 2032 and the use of 100% hydrogen from 2032 onwards. HSE considers that a direct like for like comparison is inherently challenging and comes with limitations on the level of confidence that can be applied to it. The risks associated with the live operation of the natural gas system comes with a long historical record, compared to the desk top modelling applied for the hydrogen risk assessment. This is an unavoidable constraint when dealing with a proposal for a new technology.

The QRA modelling demonstrates that all planned risk reduction measures could, on average, reduce the risks from a hydrogen system to slightly above those from natural gas. Additional risk reduction measures will be required to lower the risks further. The QRA provides examples of the further risk reduction measures that would be considered. Site-specific risk assessment would then inform when these additional mitigation measures would be deployed. The evidence indicates that it may be possible to manage the average levels of risk associated with the operation of a hydrogen network to the level of the natural gas system.

While the evidence suggests that the average risk of fatality could be managed to the level of natural gas, evidence points to the potential for greater damage to arise from incidents involving 100% hydrogen.

Overall, the QRA model forms the basis for an input into a future ALARP demonstration. However, HSE still has some concerns regarding the inputs to the QRA model which could lead to different risk estimates, which could influence the consideration of appropriate risk reduction measures

HSE’s main observations are outlined below:

- The model used for the QRA did not include all the results from the ignition consequence work and the helium testing. The model has since been updated and work by the networks (DNV Report 10474440-4) indicate that

the results in the QRA are likely to be cautious. It needs to be ensured that this updated version of the model is used for any future risk estimates.

- Within the QRA, it has been assumed that failure frequencies of iron pipes will not change significantly with the introduction of hydrogen. HSE is not satisfied that sufficient evidence has been provided to accept this assumption.
- Although the air ingress work has indicated that it should be possible to prevent flashback through suitable design of appliances, this has not yet been proven to definitively be the case. In addition, the work on air ingress has concentrated on the domestic house setting, meaning there are potential uncertainties for MOBs and for the industrial/commercial sector. This is an area that may require further consideration in future iterations of the QRA and for any site-specific QRAs.
- Potential Loss of Life (PLL) has been used widely within the report with individual risk only quoted in some instances. Tolerability criteria exist for individual risk but not PLL and it would be useful to be able to compare the individual risk to the criteria for the different scenarios modelled. This means that only limited comparison has been made against natural gas individual risk, which limits the conclusions that can be drawn.
- Some of the layouts chosen to calculate risks from commercial buildings are not worst case. Relatively common layouts that could lead to higher risks have not been explored.
- There is a potential underestimation of the effectiveness in reducing risk by moving boilers to external locations in non-domestic buildings. This risks masking potential safety benefits which would otherwise be considered.

Additional consideration could also be given to the following:

- Vulnerable people do not seem to have been considered in the QRA in terms of potential impacts e.g. causing gas release, detecting gas and taking safety actions.
- There are some concerns around the level of risk reduction assumed for alarms. Apart from reliability issues, will they be able to be located to detect all leaks (under floorboards, for example)? Will they be in every room where there is an appliance? Will they need to be connected to the mains to ensure a degree of reliability?

- Information was not available for approximately 4.7% of the GB pipework. Comment is required on the need for sensitivities for scenarios related to materials, conditions, etc.
- Modern houses may contain trickle vents around windows, which are much less apparent than a single vent of the same area but could be equivalent. Including the cost of retrofitting vents in such houses could be overestimating the cost of providing additional ventilation.
- Has account been taken of ageing populations or those with impaired cognitive ability, or reduced senses? Options such as configuring gas detectors to stop the supply automatically via the meter EFV or separate AIV should be considered.
- User behaviour can change in the presence of automation. There appears to be a knowledge gap when considering how people will respond if they know an alarm will trigger a remote response, and also if they know that an AIV will be activated in the event of a leak.

Depending on the consideration of the above, the results of any future QRA could be subject to change.

Section 12. Mitigations

The mitigations identified and the proposed approach to their application appears generally appropriate. However, the research on air ingress is evolving and mitigations have not been developed or presented for assessment. HSE considers this a significant evidence gap.

It is noted that there is the potential to update the proposed mitigations as more information becomes available and subject to technological improvements between now and any planned roll-out.

Further scrutiny would need to be applied to the extent of the identification and replacement of domestic steel services in the Local Distribution System. As a minimum, each service should be confirmed as having suitable integrity at the time of conversion.

HSE notes the overall reliance on the principle of site-specific risk assessment for domestic conversion using location specific data and conditions to determine the mitigations to be applied by exception. It would be important to ensure competency and consistency of risk-based decision-making at scale.

HSE expects that, initially, a degree of conservatism would be incorporated into any risk-based decision making around the application of mitigations to account for the uncertainty associated with the use of a novel technology.

Introduction to proposed mitigations

The emphasis of the work in the Hydrogen Risk Mitigations GDN Risk Mitigations Selection Proposal rev 1.0 report is on the below 7 bar distribution assets and its end-users. It excludes transmission systems, storage, compressors and industrial users, all of which will require bespoke risk assessment. Controls and mitigations associated with risks from air ingress are out of scope as these are still in development. Although MOBs are mentioned, they are considered in more detail in the SGN project Decarbonisation of Multi-Occupancy Buildings Feasibility Study: Hydrogen in MOBs, GDN Aligned Summary Report¹⁰⁷ which is discussed in section 10.3. End use appliances are not within scope of this assessment.

¹⁰⁷ Decarbonisation of Multi-Occupancy Buildings Feasibility Study: Hydrogen in MOBs, GDN Aligned Summary Report, SGN, 2024

The report looks at measures to reduce the societal risk, rather than the individual risk, as it is stated that the individual risk is generally already low and that a clearer picture can be derived from modelling large populations and assessing averages.

The report recognises that there is a need to demonstrate that all network and end-user assets and appliances are suitable for the transportation or combustion of hydrogen. For networks, this will impact hazardous areas and ventilation for above ground installations (AGIs). For end-users this will require new hydrogen appliances. It is not foreseen by the report that there will be a requirement to increase ventilation in end-user settings, but some MOBs will probably require updates to their riser systems.

The report has considered a number of factors to determine the suitability and practicability of any measure, including customer behaviour factors, customer acceptability and technology readiness levels. The report goes through each mitigation measure considered, stating whether or not it will be applied and in what circumstances, together with justification for the decisions made.

HSE's evidence assessment

The application of the mitigations to different parts of the network are presented below. They consider whether the mitigations are:

- Applied and existing – these are mitigations that currently are or could be deployed for natural gas and would continue to be applied.
- Additional mitigation applied universally – this means the intention is to apply these mitigations in 100% of cases.
- Additional mitigations applied by exception – a case-by-case assessment would determine whether the application of these mitigations is required. However, there is no intention to apply them universally.
- Mitigation not applied- these mitigations are considered applicable for the risk category but have not been applied. A justification for their rejection is included in the report.

For the distribution system

Existing and applied risk mitigations below 7 barg:

- Continued targeted replacement of metallic mains in line with the HSE Iron Mains Risk Reduction Policy (IMRRP).
- Continued replacement of failed assets.
- Routine network inspection and maintenance, after conversion.
- Use of hydrogen detectors and remote detection.
- Odourisation of the system.

- Developments and improvements in leak prevention and asset management identified through increased leakage surveys (within the existing natural gas network).

Mitigations to be applied universally:

- Targeted replacement of additional metallic mains where a risk assessment has identified a greater than 1 in a million chance of fatality with hydrogen usage.
- One-off upstream inspection and intervention before conversion to assess network suitability.

Mitigations to be applied by exception:

- Replacement of steel services.
- Retrospective installation of EFVs on some services at the main.

HSE considers that the mitigations, and their proposed application are reasonable but further scrutiny would need to be applied to the extent of the identification and replacement of domestic steel services. The report states that the remaining 1.15 million steel services that will be in operation post-2032 could be, as part of a conversion programme, identified and replaced with PE. HSE notes that this option is not proposed as it is considered that the costs are grossly disproportionate and there may be locations where the use of steel could be considered favourable. The continued presence of steel services of unknown conditions is a concern. As a minimum each service should be confirmed as having suitable integrity at the time of conversion.

For domestic settings

Existing and applied mitigations for a domestic setting, as detailed in the NHSA:

- Routine voluntary and/or obligated (i.e. landlord duty) appliance inspection and maintenance.
- Pre-existing ventilation.
- Ongoing relocation of internal meters that have been identified as at risk or unsafe.

Applied universally:

- The installation of a mechanical EFV located immediately downstream of the ECV set to a maximum nominal flow rate of $20 \text{ m}^3 \text{ hr}^{-1}$, and a second EFV in the hydrogen smart meter set at 1.15 times the total demand for all installed appliances.

- Remote hydrogen detectors in properties with hydrogen appliances that provide an audible alarm and alert the Emergency Response Service Provider when a leak is detected.
- Relocation of unsafe meters where the existing location cannot be made to meet hydrogen safety standards.
- Inspection and testing of installation pipework in preparation for conversion.

Applied by exception:

- Additional ventilation.
- Secondary additional EFVs on downstream spurs e.g. to cooking appliances and fireplaces.
- Thermal cut off (TCO) devices incorporated into the mechanical EFV.
- Replacing some gas appliances with alternative energy sources.

HSE considers that the mitigations for domestic settings, and their proposed application appear appropriate.

Universally applied detection is viewed as a positive mitigatory step however the suitability and effectiveness of detection in domestic settings would need to be established. This is not anticipated to represent a fundamental barrier, however, such questions as will detectors be able to be located to detect all leaks (under floorboards, for example) and how user behaviour would change in the presence of automation (such as the proposed use of remote hydrogen detectors linked to emergency response) are examples of evidence gaps that would need to be resolved.

HSE would expect to see the potential for smart detection with integrated Automatic Isolation Valves to be explored further as technology evolves.

HSE notes that fitting the EFV's at the ECV would not protect the property from service pipe damage or interference and would only protect against larger leaks. Leak detection would therefore become a key mitigation. The replacement of metallic services with polyethylene is expected to bring about a significant reduction on service pipe leaks, especially those where gas is able to move through the ground and enter a property.

HSE notes that an elevated pressure test had been proposed as part of the one-off downstream inspection prior to conversion. Currently a pressure strength test at between 82.5 mbarg and 85 mbarg is included in IGEM enabling standard H2. Further data is required on this topic to try and gain an understanding of how many leaks are likely to be identified by the test and the scale of any adverse effects that the test could cause.

HSE notes the overall reliance on the principle of site-specific risk assessment for domestic conversion using location specific data and conditions to determine the mitigations to be applied by exception. At scale this could lead to a degree of variability in its application simply due to the extent and volume of the decision-making being undertaken. The gas distribution industry would need to ensure that work force competency and consistency of decision making is carefully planned and managed at scale. HSE expects that initially a degree of conservatism would be incorporated into any risk-based decision making around the application of mitigations to account for the uncertainty associated with the use of a novel technology.

For commercial buildings

Existing and applied risk mitigations:

- Routine riser inspection and maintenance, where present.
- Routine voluntary and/or obligated appliance inspection and intervention.
- Pre-existing ventilation.
- Continued relocation of internal meters identified as at risk or unsafe.

Applied universally:

- Inspection and intervention to ensure assets are IGEM/G/5 compliant and, where they are not, assess for suitability for hydrogen.
- Inspection and testing of installation pipework.
- Installation of a mechanical EFV immediately downstream of the ECV and a second incorporated into the smart meter. Trigger points to be set specific to the use of hydrogen.
- Installation of remote hydrogen detectors that provide an audible alarm and alert the Emergency Response Service Provider on detection of a hydrogen leak.

Applied by exception:

- Swapping to an alternative decarbonised energy.
- Installing secondary, additional EFVs on downstream spurs.
- Installing a Thermal Cut Out (TCO) at the meter.
- Installing additional ventilation.
- Installing 'Smart' and 'Local' hydrogen detectors, providing the additional function to notify other appliances and fittings, such as an AIV, and to provide wider local audible alarms.
- Additional relocation of internal meters.
- Relocation of internal appliances.

While the mitigations proposed appear reasonable further work would be required to determine the approach to their deployment. Insufficient evidence has been presented at this time for HSE to draw definitive conclusions.

In particular, HSE notes that air ingress is a developing and evolving area of research and complete demonstration has not been made to be able to determine whether or not the relevant risks to commercial settings can be appropriately managed and mitigated.

For industrial users

A site-specific risk assessment will be necessary to identify mitigations that will be required to be implemented to demonstrate that the site is ALARP.

Consideration of air ingress will also be critical to determining whether or not risks can be appropriately managed.

Summary

The report suggests that when the identified measures are applied the societal risk is shown to be broadly the same as that for natural gas. It states that when accounting for the additional measures identified that will be applied by exception the societal risk from hydrogen will be at least as safe as natural gas.

The report includes additional mitigations that have not been applied in the QRA e.g. additional targeted replacement of metallic mains and installation of two EFVs on non-domestic buildings.

Conclusions

Overall, HSE considers that the mitigations identified and the proposed approach to their application appears generally appropriate. However, the research on air ingress is evolving and mitigations have not been developed or presented for assessment. HSE considers this a significant evidence gap.

HSE notes the overall reliance on the principle of site-specific risk assessment for domestic conversion using location specific data and conditions to determine the mitigations to be applied by exception. At scale this could lead to a degree of variability in its application simply due to the extent and volume of the decision-making being undertaken. The gas distribution industry would need to ensure that work force competency and consistency of decision making is carefully planned and managed at scale. HSE expects that initially a degree of conservatism would be incorporated into any risk-based decision making around the application of mitigations to account for the uncertainty associated with the use of a novel technology.

The report has considered societal level risk reduction that can be applied generally. There will still be localised areas that could be subject to much higher levels of risk e.g. close proximity to remaining cast iron mains. The approach taken of considering overall societal risk through the PLL (Potential Loss of Life) will not highlight such populations as these localised risks will be spread across the population as a whole. It is not clear how this issue will be addressed from the report.

There could be specific applications where gas detection and AIVs could give better protection than larger capacity EFVs e.g. large domestic, MOBs, etc. This requires further consideration.

The report states that, if a measure is recognised as being good practice, then it should be applied regardless of the results of any Cost Benefit Analysis. HSE notes that 'Relevant Good Practice' is not yet fully developed for hydrogen use in heating.

HSE notes that neither the QRA nor the risk mitigations report consider the risks associated with decommissioning sections of the existing natural gas network. This would require further consideration.

HSE notes that fitting the EFVs at the ECV does not protect the property from service pipe damage or interference and only protects against larger leaks. Leak detection would therefore become a key mitigation. The replacement of metallic services with polyethylene is expected to bring about a significant reduction on service pipe leaks, especially those where gas is able to move through the ground and enter a property.

When considering the role and effectiveness of hydrogen detectors, further assurance would be required relating to failure/decay of protection over time and human factors. The detectors may become less reliable over time meaning that their impact on risk reduction would be decreased. No measures for maintaining levels of safety have been presented.

HSE notes that smart detectors linked to AIVs have been discounted on the basis of technological readiness as predicted by 2032. However, HSE would expect to see the potential for this mitigation to be explored further as technology evolves. HSE concurs with the evidence provided that a greater risk reduction could be achieved with the development of smart detectors.

It is noted that there is the potential to update the proposed mitigations as more information becomes available and subject to technological improvements between now and any planned roll-out.

Section 13. MOBs Risk Assessment

The MOBs QRA is a developing tool which could support a demonstration of how the risks associated with hydrogen use in MOBs could be managed in line with regulatory requirements. However, a full evidence demonstration has not been made at this time. Further information is required to inform appropriate risk assessment and consideration of mitigations. Changes to the results of the MOBs QRA could lead to changes to the results of the GB QRA.

The QRA results indicate that installation of an energy centre, if one is not already available, achieves the greatest reduction in risk. However, installation of energy centres is to be determined by site-specific assessment and may not be practicable in every case.

While the development of the QRA would support the consideration of appropriate mitigations, the QRA results indicate that, in the event of an incident, greater damage could result, including a higher risk of building collapse when compared to natural gas.

Introduction to the MOBs Risk Assessment

A MOB is defined in the submission as a building that meets one of two criteria:

- The building contains at least 3 domestic dwellings
- The building contains a mixture of domestic dwellings and commercial units, with there being at least 3 dwellings and units in total.

The QRA used the same model as that for the GB QRA i.e. DNV's CONIFER risk assessment package, that was modified to consider risks that are specific to MOBs e.g. from risers and laterals, building collapse, energy centres etc.

Results

2 and 3-storey buildings

- The report states that risk per dwelling for 2- and 3-storey buildings that have been converted into flats is slightly higher than for an equivalent 3 storey single occupancy house. This occurs for both natural gas and hydrogen and is due to the close proximity of the dwellings to each other and the potential for an explosion in one flat to affect people in another. This effect is similar to that seen when comparing risks associated with

detached, semi-detached and terraced houses. The risk increases with the density of dwellings and the effect is larger for hydrogen without additional mitigation measures.

- The risk mitigation measures that could be applied in 2- and 3-storey buildings could be similar to those applied in houses.

Buildings over 3-storeys

- The report states that individual risks of fatality from natural gas all fall below 1×10^{-6} per year. Most of the hydrogen individual risk values are also below this level, even without additional mitigation measures however they are still higher than for natural gas. The exceptions to this all have internal risers and internal meters. The risks can be reduced below this level in all buildings, but the mitigation measures required vary by building.
- The risk associated with spreading building fires is approximately the same for both natural gas and hydrogen across all building types.
- Building collapse is a significant risk contributor when using hydrogen, in contrast to natural gas, and the risk increases in a non-linear manner as the building height increases.
- The total risk posed by all potential gas leaks, from both gases, in a building increases with increasing building height. The effect is more noticeable with hydrogen due to the effects of an explosion on adjoining flats and due to the possibility of building collapse.

The report states that the mitigation measures that will be effective at reducing risk in MOBs are:

- The installation of an energy centre, if one is not already available, achieves the greatest reduction in risk associated with gas use. Energy centres pose a lower risk than supplying gas for heating to individual flats within a building, especially if the gas is not used for cooking either.
- Installation of gas detection with the ability to raise a local alarm and notify a control centre of the presence of gas.
- Where present, relocation of internal risers that are not in sealed ducts. If this is not possible, ensuring that they are fit to carry hydrogen and undertaking regular inspections to control their failure frequency.
- Improved ventilation in flats or at least ensuring that a minimum level of ventilation is present.
- Relocation of internal meters to external locations can be beneficial in some buildings.

In addition, removal of cooking appliances, or the removal of boilers from individual flats has been considered and has been shown to result in a moderate reduction in the risk. In this scenario, however, the risers, laterals, meters and downstream

pipework must be retained. This is much less effective at reducing the risk than moving to an energy centre for heating with electrical appliances for cooking.

MOBs Recommendations

The MOBs QRA makes a number of recommendations. These are:

- Gathering more data on MOBs configurations would aid in decisions regarding the process of converting buildings to hydrogen. In particular, it would be beneficial to get an accurate picture of:
 - Which buildings have energy centres, and their purpose. Some are used to heat the whole building while others only heat communal areas such as hallways and stairwells.
 - How many flats in each building have their own gas supply and whether it is used for heating, cooking or both.
 - The population of gas appliances in use in buildings of different types.
 - Which buildings have meter banks, including how many and where they are located.
 - The numbers of risers in each building and their locations. Ideally, information on their material, diameter and joint type would also be recorded.
 - A better indication of the number of risers in operation, along with methods to match failure data to risers of specific materials and locations within the buildings.
 - More data on the response of different building types to internal explosions, particularly building collapse, would be beneficial to provide a better indication of the risks experienced by the occupants.
- Appropriate ventilation requirements within energy centres should be determined. If the required level of ventilation cannot be achieved, alternative options such as installation of gas detection should be considered.

HSE's evidence assessment

The report recognises the need to gather further information to inform risk assessment and consideration of appropriate mitigations. Beyond the information gaps already identified in the submission, HSE also considers that:

- The work undertaken shows that pipework velocities are significantly higher for hydrogen than natural gas in the majority of MOBs investigated, and above the natural gas velocity limit. The consequences of this finding are not made clear e.g. conclusions on suitability of pipework or building types. Instead, it forms part of a recommendation for further work and so this

remains an evidence gap and is an input to the QRA that has not been calculated.

- The feasibility report states that more work is needed to determine what the typical air permeability rates are in individual dwellings in MOBs. This affects the potential for gas build up and hence the consequences. This represents an evidence gap and is an input to the QRA that has not been calculated.
- There is a recommendation for further guidance for the design of explosion relief for energy centres. This is a technical gap that requires closing.

Conclusions

The MOBs QRA is a developing tool supporting a demonstration of how the risks associated with hydrogen use in MOBs could be managed in line with regulatory requirements in the event of a roll out at scale. However, a full evidence demonstration has not been made at this time.

As recognised in the MOBs QRA submission there is a need to gather further information to inform appropriate risk assessment and consideration of mitigations. If this further work leads to changes to the input to the MOBs QRA then there could be an impact on the GB QRA results. MOBs are included in the GB QRA and so any change in how the risks from the use of hydrogen in these buildings are assessed will potentially impact the results of the GB QRA.

HSE notes that while further inputs into the QRA modelling will be required, the results point to building collapse being a significant risk contributor when using hydrogen, in contrast to natural gas, and that the risk increases in a non-linear manner as the building height increases.

Section 14. The National Hydrogen Safety Assessment

The NHSA provides a useful framework for a general approach for a conversion to hydrogen. It provides an insight into how more detailed plans would be developed to allow progression to delivering hydrogen conversion. However, the evidence is generic in nature, potential roll out pathways are uncertain and comprehensive conversion and operating procedures have not been prepared.

Further work would be required to address asset identification and verification, network maintenance regimes and the potential for integrated smart detection and AIV deployment.

Developing the necessary competencies that would be required to support a roll out at scale presents a challenge.

Introduction to the National Hydrogen Safety Assessment (NHSA)

The NHSA aims “to describe the minimum general arrangements that will be required to demonstrate that a network and its connected properties can be converted to hydrogen and be operated safely, with risks appropriately managed for those working on the system or whose safety may be impacted, including the general public”. The NHSA includes transmission, distribution and end use, but not production or storage of hydrogen. The NHSA proposes a general approach to conversion, an “overarching strategy”, rather than detailed plans, which the gas network industry would need to develop, in advance of any future roll out.

A process is described for converting each part of the gas system, including transmission, distribution, MOBs and other end users. It considers grid conversion, sectorisation to facilitate incremental conversion of an area, methods of isolation, time off gas, overall disruption and environmental impact.

A description of how the sectorisation would be undertaken is given, including how the sector sizes will be chosen and how they will vary over time as industry experience is improved. An outline is provided of what would be expected to demonstrate regulatory compliance.

Asset identification is critical to understand the suitability of the infrastructure to convey hydrogen prior to conversion. Risk assessment is key to demonstrating

suitability for conversion and understanding the potential risk to members of the public. The NHSA describes how it is critical to have confidence in data associated with the specific infrastructure being converted to hydrogen.

The NHSA describes the approaches to be taken to assure asset information suitability and identify those assets of unknown status or where there are poor quality records. Assets were to be assessed according to the following groupings:

- Distribution pipes (LP/MP/IP) and associated components
- Services
- Transmission Pipes (LTS/NTS)
- Pressure Regulation (All pressure ranges)
- MOBs & Multiple Occupancy Commercial Structures
- Domestic Installations
- Non-domestic Installations

HSE's evidence assessment

HSE agrees with the NHSA submission assertion that it is subject to a number of key limitations, namely:

- The evidence is generic in nature and not specific to any one network or user of hydrogen.
- The location and scale of hydrogen production facilities and therefore location of hydrogen networks and potential role out pathways is uncertain.
- Comprehensive conversion and operating procedures will not be prepared, these will follow a positive hydrogen for heating policy decision.
- There will be no widescale trained workforce, again training will follow a positive hydrogen for heating policy decision.

It is stated that the NHSA is therefore aiming to set out how the evidence submitted to HSE should be applied to the conversion and operation of specific assets. It also aims to describe how outstanding evidence gaps will be addressed in the future. HSE notes that this submission assumes application of a safety case regime for 100% hydrogen. Consideration of the future regulatory framework for 100% hydrogen is discussed in Section 2.

The focus of the NHSA is on distribution and end use, although the National Transmission System (NTS) network is also included. It is proposed that NTS and LTS pipelines and others operating above 7 barg will be subject to specific asset assessment for operation in hydrogen service rather than a generic approach to assessment being applied. HSE considers this to be an appropriate approach.

Beyond the NTS, the NHSA covers distribution at 7 barg and below and all types of users i.e. domestic, commercial, small and large industrial. It is noted in the NHSA that a key assumption is that the gas network operators will be responsible for overall management of the conversion process, including for domestic users. The NHSA notes that alternatively an overarching conversion body could take on the role instead, although the key principles in the NHSA would remain applicable. HSE notes that this management arrangement has not yet been determined.

The NHSA states that individual site-specific risk assessments will be completed to assess the risk to different consumers, assuming that the universally applied “planned” mitigation measures have been installed or implemented. Additional mitigations would then be applied by exception as determined by the risk assessment. This approach is detailed in Hydrogen Risk Mitigations GDN Risk Mitigations Selection Proposal rev 1.0 report and is discussed in Section 12

The NHSA lists a number of assumptions that are fundamental to the conversion which should be applied for bespoke risk assessments. These are:

- Hydrogen in the distribution system is expected to be at least 98% pure, as given in the hydrogen gas quality specification PAS 4444, IGEM/H/1 and IGEM/TD/21.
- The transported hydrogen will be odourised to allow detection as is currently the case with natural gas.
- Members of the public will not be expected to detect whether any escape of gas is natural gas or hydrogen, and reporting will continue to be via the gas emergency reporting service for all gas escapes.
- Appliances and meters will be replaced with hydrogen ready versions in line with GAR and PAS4444 requirements (noting that development is required to address the risk arising from air ingress). Bespoke industrial and commercial apparatus, where not replaced, will be modified for safe hydrogen use.
- Network pressure tiers will remain unchanged (e.g. low-pressure distribution pipes will continue to have a maximum operating pressure of 75 mbar).
- Current domestic appliance inspection and maintenance requirements will continue, including landlord safety requirements where applicable.
- Dutyholders will ensure compliance with DSEAR, including risk assessment and ensuring suitably rated ATEX equipment is used.
- Completion of the tier 1 iron mains risk reduction program, including replacement of associated steel services.

It will be necessary to undertake pipeline risk assessments for the conversion of transmission pipelines. HSE notes that the approach to determining asset condition and assessment has been presented but these risk assessments have not been presented as part of the evidence base submitted. New hydrogen transmission

pipelines will also require a risk assessment, as part of the Pipeline Safety Regulations (PSR) requirements to show they are safe to operate.

Unknown assets

One of the key challenges for any conversion will be the ability for the gas network industry to adequately identify asset location, suitability and condition.

The NHSA considers unknown assets as assets absent from the “records set”, records with key data incomplete and those assets duly recorded but with inaccurate data. Where inaccuracies or omissions exist, efforts need to be implemented to determine the correct asset identification as well as validating completed records are correct. The NHSA describes the approaches to be taken to assure asset information, identify those assets of unknown status or where there are poor quality records, in preparation for conversion and operation. This considers assets that are readily accessible and assets that are not readily accessible e.g. due to being within building fabric or below ground etc...

HSE considers that networks and non-domestic users will need to assess their infrastructure records and asset status prior to conversion as the basis for demonstrating network suitability. For domestic users, networks will need to make arrangements to identify appropriate required mitigations prior to conversion, requiring suitable surveys to be carried out by personnel competent in the means and application of required domestic dwelling inspection.

While not detailed in the NHSA, HSE notes that evidence on asset verification has indicated that asset identification was to be augmented during excavation activities associated with the iron mains replacement program, and additional replacements to facilitate acceptable asset performance and risk. Further asset verification was also to be facilitated during excavation activities to install additional pipeline isolation valves to facilitate sectorisation prior to conversion.

HSE notes that, in the case of buried assets, asset identification may include partial excavation or other means to establish asset data to an acceptable level of confidence. The identification of type and nature of some services remains an issue with differing approaches and ages existing side by side in some instances.

Where asset identification can't be specifically assured, then other means of risk assessing the impact of the level of confidence in asset identification and consequence of any credible failure must be applied.

Overall, HSE considers that the approach to the identification of unknown assets appears reasonable. However, this remains dependent on the development of detailed scopes and the quality of the outputs. Where asset identification can't be specifically assured, the means for addressing this has yet to be determined and as such this represents an evidence gap at this stage.

In the absence of a complete network survey this would leave a degree of evidential uncertainty. Risk based judgements on the comprehensiveness of surveys would need to be made.

Identification and replacement of steel services

Approximately 1.15 million steel services will remain in service post-2032 (4.3% of the full population). They present an increased risk in the majority of circumstances due to the effects of corrosion. The NHSA sets out that as part of a conversion programme, these services could be identified and replaced with PE services. Doing so in tandem with the conversion programme is likely to reduce overall effort, disruption, and cost, compared to a proactive programme prior to conversion.

The continued presence of steel services of unknown conditions continues to be a wider concern and the introduction of hydrogen into such services heightens that concern. As a minimum each service should be confirmed as having suitable integrity at the time of conversion.

Text on supply emergencies being considered

Maintenance

The networks will require maintenance and inspection regimes to be modified, which are likely to be more conservative in order to validate the evidence gathered or otherwise identify issues before they become a matter of concern. The NHSA states that maintenance and inspection activities will be required to be undertaken to maintain the network in a safe and efficient condition. This includes both proactive and reactive maintenance including replacement work activities. The natural gas network utilises Reliability Centred Maintenance (RCM) approaches to plan and deliver maintenance. The operational data to inform an RCM philosophy will not initially exist following conversion and maintenance frequencies will revert to a calendar-based approach until sufficient data is obtained over time. Written Schemes of Examination (WSE's) will require review under the Pressure Systems Safety Regulations (PSSR) and any changes to inspection activities or frequencies implementing. HSE considers that this represents a reasonable approach.

It is of further note that the local distribution system relies largely on detection of leaks, i.e. intervention at time of failure. The gas network industry has indicated that enhanced leak detection and leak surveys will be implemented, especially in the case of remaining iron main infrastructure. While HSE considers enhanced leak detection would be beneficial for risk reduction, details have not been provided. Leak prevention should be considered the primary objective.

Mitigations

The application of the mitigation measures proposed in Hydrogen Risk Mitigations GDN Risk Mitigations Selection Proposal rev 1.0 report is given in the NHSA. Consideration of the mitigations and their proposed application is undertaken in Section 12.

Conclusions

Overall, HSE considers that the NHSA provides a useful framework for a general approach for a conversion to hydrogen. It provides an insight into how more detailed plans would be developed to allow progression to delivering hydrogen conversion.

HSE notes and agrees with the gas networks observations that:

- The evidence is generic in nature and not specific to any one network or user of hydrogen.
- The location and scale of hydrogen production facilities and therefore location of hydrogen networks and potential role out pathways is uncertain.
- Comprehensive conversion and operating procedures have not been prepared.

In addition, HSE notes the challenges of developing the necessary competencies that would be required to support a roll out at scale.

HSE notes that further work would be required to address:

- Asset identification and verification.
- Maintenance, including:
 - clarification on enhanced leak detection approach and efficacy.
 - review of written schemes of examination (for compliance with PSSR).
 - transition from RCM to calendar based maintenance regimes.
- Who would be responsible for conversion.

Section 15. International Comparisons

Overall, the international comparisons work is informative. HSE considers that further information gathering, including from trials and demonstrations, could provide operational learning and support validation of experimental data.

Where evidence is used in support of any GB future gas network industry proposals for approaches to risk management, then this would need to be relevant to the circumstances of the evidence demonstration being made.

Introduction

International evidence gathering exercise was carried out by the gas network industry. This was reported in two separate summary reports, one covering distribution aspects in converted networks and one covering domestic aspects, the latter based on a series of ongoing trials in the Netherlands and Germany.

- Hydrogen heating pilot projects evaluated were:
- Enexis, Wagenborgen Pilot (Netherlands, 33 houses, proposed ten-year duration, pressures up to 8 bar)
- Aliander, Lochem Pilot (Netherlands, 11 occupied homes heated via hydrogen using the existing natural gas grid, proposed three-year duration)
- Hohenwart, H2Direkt (Germany, ten domestic properties and one commercial property, PE pipeline, seven-month duration)
- Hydrogen research programme assessed:
- HyDelta (Netherlands)

A report for each trial/ project was developed from engagement with each project and included information gained through on-line meetings, face-to-face visits and project reports shared with the gas network industry. It is noted that many products used in both Germany and the Netherlands are also used in the UK and feature in EN standards across Europe. It is stated that the transferability of learning should therefore be high. However, the experiences of other European countries also considering repurposing for hydrogen were not included. Projects in both the Netherlands and Germany continue to gather evidence, data and real-life experiences from both consumers and operators.

HSE's evidence assessment

End user evidence

This is stated as having been a valuable exercise, with new learnings and similarities with European networks providing useful insights into safety, technical and operational matters as follows:

Pipework assurance: Assurance provided by predominantly pressure/ strength testing, visual inspection and replacement in some instances. Existing installations were tested at operating pressure and at an elevated pressure of 120-125 mbar. It was noted, however, that in several cases the installations were new.

Ventilation: All projects assessed ventilation requirements, meaning the reduction of potential hydrogen accumulation. Computational Fluid Dynamics (CFD) was used in some cases. Ventilation provision found these to be 'as normal', i.e. at the same level of requirement as for natural gas.

Hydrogen detection: All projects featured hydrogen detection, with audible alarms in both countries, while in Germany these were linked to a hydrogen supply isolation mechanism. Alarm thresholds were around 4,000 ppm. The use of detectors was highlighted as being specific to the trial nature of the projects.

Excess flow valves: Gas meters did not include any integral EFVs, these were installed in the gas service pipe to the property.

Location of meters and appliances: There were no differences from standard natural gas practices in terms of meter locations. All projects used only new hydrogen combination boilers which were installed for the projects. Cooking with gas in Germany is rare, accounting for less than 5% of appliances, whereas levels in the Netherlands are similar to the UK.

Air/oxygen ingress: This was investigated in two of the Dutch trials. The possibility for oxygen to permeate into gas systems when the supply was isolated for a period of time was acknowledged. A value of 5 vol% oxygen was quoted for a 16 mm PE pipe after 15 days, quoted as creating a flammable mixture with hydrogen present in the pipe. Realistic 'downtimes' in the Netherlands and UK were compared in the context of this finding. Also, the analysis covered both PE and PVC pipes, the latter are not used in the UK, but PE pipes are and hence the findings are valid for the UK case. It was recommended that, in pilot projects, the gas composition should be monitored where there is prolonged shutdown of hydrogen.

The gas network industry submission noted that operation of live hydrogen trials in Europe offers an opportunity to support further understanding. They report that having operated some of these trials for >1 year, there is still no witnessed evidence of the occurrence of oxygen amounts above accepted limits.

Overall, it is recognised that the risks associated with oxygen ingress into pipework is an issue that requires further investigation. HSE notes that any learning and validation would need to take account of system configurations.

Purging: Indirect methods using nitrogen were used, with various purging points installed

Conversion strategy: All projects were subject to a degree of pre-works in advance of the actual conversion day. The aim was to minimise the 'off-supply' time of the consumer.

Distribution evidence

Findings from the pilot projects and HyDelta research programme are summarised as follows:

Overall system performance over time: Evidence is being generated on aspects such as hydrogen injection, odorisation, material compatibility and operational performance of assets. Use of similar equipment and standards means the learnings are also applicable to the UK. All the pilots used THT as odorant, with some issues being noted on odorant absorption into PE pipe walls.

High to low pressure regulator performance: These are similar in design and operation to the UK. The most common regulators in Europe for natural gas are stated as being functionally suitable with hydrogen. In the Wagenborgen pilot scheme the plan is to operate for ten years, although it is noted that long term performance has not been demonstrated for regulators. NdFeB based magnets in flow meters in use since 2022 are described as starting to disintegrate under the influence of hydrogen, with further monitoring underway.

Velocity and pressure behaviours: No material impacts have been noted. No detrimental effect of increased gas velocity on filters was noted.

Springs performance over time: It is stated that short term testing has proven the suitability of springs, although dimensions, surface condition and steel grade have not been detailed. The Lochem pilot had been running since 2022, and the Wagenborgen pilot will run for ten years. Long term durability results are therefore awaited.

Hydrogen permeation in live environments: Not found to be an issue during gas flow, but noted when the hydrogen gas supply is isolated (see detail in earlier section)

District governor design changes and general housing ventilation upgrades: All pilot projects increased ventilation for their PRI kiosks, noted as a key mitigation to reduce hydrogen build-up. Different approaches were taken including addition of large roof ventilation ducts or addition of ventilation on the housing doors.

Repair techniques and repair materials compatibility with hydrogen: Development of standards, procedures and specialist training including welding of branch fittings and leak repairs. Each pilot project had developed their own standards specific to each operator and their network.

Overall, the findings of the international evidence gathering exercise provide some valuable insights for the UK conversion. The exercise also identified that there are a growing number of opportunities to learn from international sources which were not able to be captured currently. This could include other pilot projects, other European countries and those outside Europe. Furthermore, some of the pilot projects have longer to run, generating valuable long-term performance and compatibility data. However, this is not currently available and represents a gap in current knowledge, especially for materials compatibility.

It is stated that the most common regulators in Europe for natural gas are functionally suitable with hydrogen and that existing gas regulators can be repurposed with no impact on their operational performance. Regulators invariably contain many different types and grades of material but there is no mention of materials of construction or any caveats/limits on their use in hydrogen. Long term performance is not yet demonstrated.

Information is presented on experience of the performance of springs under hydrogen service. One pilot has operated since 2022 with no reported issues. A further pilot will operate for 10 years. It is important to know the grade of material used in these springs, if possible, as this component is one that has been highlighted as being of potential concern in hydrogen service in other studies due to the requirement to use high strength steel.

There are some uncertainties regarding odorant injection, and its absorption into PE pipe walls. The injection rate may need to be modified to allow for this, but this is not detailed further.

A specific type of magnet is noted as showing signs of disintegration in the hydrogen pilot running since 2022. This phenomenon has been reported in the literature and may also have significance in the case of in-line pipeline inspection tools that use magnets to measure wall thickness of steel pipes. The performance of magnets under long term gaseous hydrogen remains a knowledge gap. Similarly, repairs and repair procedures are described but material details and their performance characteristics in the trials are not known. Long term performance of repair materials remains a gap.

On PRI ventilation designs, evidence relates to only two installations so does not seem a valid basis for widespread use in the UK. Instead, it would be expected that the ventilation requirements with hydrogen would come out of individual DSEAR assessments.

Conclusions

Overall, HSE considers that further information gathering, including from trials and demonstrations could provide operational learning and support validation of experimental data.

Where evidence is used in support of any GB future gas network industry proposals for approaches to risk management, then this would need to be relevant to the circumstances of the evidence demonstration being made.

Conclusions

Overall, HSE considers that it is potentially feasible to convert the natural gas system for use with 100% hydrogen heating. The work submitted to HSE constitutes a developing evidence base that is building towards a demonstration of how the risks could be managed in line with regulatory requirements in the event of a roll out at scale. No fundamental safety barriers have been identified by HSE's assessment; however, a full evidence demonstration has not been made at this time.

HSE notes the overall reliance on the principle of site-specific risk assessment using location specific data and conditions to determine such things as the replacement of unsuitable materials in a wide range of network settings, the choice of mitigations in end use and other settings etc. Whilst this more effectively tailors risk evaluation and is a fundamental premise for the management of safety in the UK, this could lead to a degree of variability in its application during a roll out of hydrogen at a national scale simply due to the extent of the decision-making being undertaken. The gas distribution industry would need to ensure that the consistency of decision making is carefully planned and managed at scale. HSE expects that, initially, a degree of conservatism would be incorporated into any risk-based decision making to account for the uncertainty associated with the use of a novel technology.

There are a broad range of issues that Government and the gas network industry would need to consider in advance of any national roll out. Currently, particular evidence limitations and constraints relate to:

- The gas network industry has identified the need for site-specific risk assessment to be undertaken for conversion, including steps to identify location, suitability and condition of pipework and assets. This means that it is not possible to determine from the evidence assessed to date the extent to which the current gas network can be repurposed without the need for remediation or replacement.
- The lack of operational data represents a constraint. Operational learning, supported by further research will be key to validating the evidence base provided.
- While the evidence demonstration supports near term potential use of hydrogen the longer-term impacts from hydrogen service remain to be determined.

- Material performance would need to be monitored to identify any emerging long-term suitability issues. If materials were shown to be unsuitable or if there is any doubt over their suitability, further action would be required.
- Full technological readiness of underground hydrogen storage, including salt cavern storage for use with fast cyclical loading has not been fully demonstrated.
- The use of line-pack (for storage) of hydrogen within the NTS will likely be compromised. The implications for the resilience of hydrogen gas supply would need to be considered.
- The repurposing of the Local Distribution System (LDS) presents a number of challenges, including:
 - While elements of the LDS will be subject to an inspection and maintenance regime, the buried and legacy pipework in the LDS presents a challenge to inspection. Reference has been made to enhanced leakage surveillance, but specific solutions have not been presented for HSE's consideration.
 - HSE considers that the approach to the identification of unknown assets appears reasonable. However, this remains dependent on the development of detailed scopes and the quality of the outputs. Where asset identification can't be specifically assured, the means for addressing this has yet to be determined and as such this represents an evidence gap at this stage.
- HSE considers that it is feasible that legacy iron pipes of suitable specification and condition can be operated in hydrogen service up to 2 barg, based upon the original design pressure of the pipework. However, there has been insufficient evidence provided so far relating to what inspection and surveillance techniques will be deployed and maintenance regime implemented over and above the current approach to enable HSE to comment on its suitability.
- Overall, HSE considers that it is potentially feasible to convert the domestic natural gas system for use with 100% hydrogen for heating:
 - HSE considers that evidence on the compatibility of typical materials used downstream of the ECV within domestic and small commercial premises shows that most conventional materials are acceptable for use in hydrogen service. However, there will be some non-conforming or unsuitable materials in some properties that would need to be replaced prior to any conversion. Removal of these non-conforming materials requires effective identification. HSE considers that additional

means of confirming the suitability of materials shall be required beyond that of visual inspection proposed by the gas distribution industry.

- HSE considers that the deployment of domestic hydrogen detectors presents a positive safety mitigation, however, robust consideration of reliability issues, ability for hydrogen detectors to detect all leaks, for example, leaks under floorboards, protection of vulnerable users and user behaviour.
- Research into air ingress being limited to domestic settings only and that the mitigation measures for air ingress into domestic pipework have not yet been developed to support a roll out at scale.
- The level of remediation or replacement of the gas networks that may be required in MOBs has not been determined.
- Only limited evidence has been presented on industrial and commercial settings. This evidence cannot be extrapolated to draw general conclusions across the diverse range of industrial and commercial settings at a national level. Any future roll out would require site-specific risk assessment.
- The modelling on ignition consequences indicates that in the event of an incident involving 100% hydrogen, greater impacts to people and property could result.
- Some industry standards have been developed to support the use of 100% hydrogen. Further work is underway to develop, update and agree relevant standards. This will support the development of Relevant Good Practice over time.

As hydrogen for heating is an emerging technology, HSE anticipates that safety management will evolve to reflect technical capability at a given time in regard to inputs such as materials, processes, and competence. This will be based on relevant consolidated findings of developing science, technology, and experience, meaning that the inputs for demonstration of regulatory compliance may change over time.

The safety considerations outlined here could result in cost and feasibility implications that would need to be determined. For example, HSE considers that a conversion to hydrogen will likely require a degree of building disruption to change out appliances, repair or replace non-conforming pipework, replace some meters etc.

HSE considers that a direct like for like comparison between 100% hydrogen and natural gas is inherently challenging and comes with limitations. The evidence indicates that it may be possible to manage the average levels of risk associated

with the operation of a hydrogen network to the level of the natural gas system. However, HSE notes that the risk modelling is sensitive to the inputs provided. Changes to these inputs could lead to different results.

References

This section outlines evidence submissions, standards and directives that are referenced through the document.

This assessment is based on evidence submitted to the programme by 29th November 2024. However, HSE notes that work on the evidence base has continued to evolve, and work has been undertaken by the Gas Network Industry to update some of the submissions HSE reviewed for this report.

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Further information

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