LTS Futures Blueprint

Pipeline and Installation Repurposing for Hydrogen Service

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Contents

1. Executive Summary

SGN undertook the Local Transmission System (LTS) Futures Project as part of the UK's national hydrogen research programme to support delivery of a net zero decarbonisation solution for customers. The project successfully repurposed a LTS pipeline and block valve installation for use with hydrogen in a live trial in 2025. In addition to the live trial the project carried out material testing, case studies and equipment assessments to assess the compatibility of the LTS assets for use with hydrogen.

The aim of this Blueprint is to outline the principles for repurposing existing LTS pipelines and installations for hydrogen service and share the learning generated from the LTS Futures Project, including the live trial. The Blueprint is not a repurposing specification. It is intended to inform the development of industry standards and specifications for the transmission of hydrogen through the LTS.

The Blueprint is based on the published Hydrogen Standards and the outcomes and learnings from the LTS Futures Project as of March 2026 and was developed in conjunction with the full-scale trial, with its practical application informing and refining the repurposing approach.

There is a significant amount of hydrogen transmission research being carried out across the world and industry standards are continuously being updated. As understanding improves it may provide opportunities to remove some of the conservatism within this Blueprint. As industry standards are published the Blueprint should be reviewed and updated.

The LTS consists of approximately 11,000 km of pipelines, some of which date back to the 1950s and 1960s, resulting in variation in design and construction standards, materials and operating environment. This variability means that this project could not address all potential construction, quality and condition issues present in the LTS. The suitability of each individual pipeline and installation for hydrogen service shall be assessed individually to ensure all relevant issues are evaluated.

It is intended to support engineering judgement and decision-making by Gas Distribution Networks (GDNs), rather than prescribe mandatory requirements. Accordingly, the recommendations and approaches described herein should not be considered obligatory where alternative, demonstrably equivalent or improved solutions can be justified.As industry knowledge, standards and technologies continue to evolve, GDNs are encouraged to adopt proven improvements without delay, rather than waiting for formal updates to this Blueprint.

Future Considerations

1. This LTS Futures Blueprint for Pipeline and Installation Repurposing for Hydrogen Service should be reviewed, and if required updated, following:
   a. Completion of the material and Pressure Reduction Installation (PRI) testing.
   b. Updates to the IGEM/TD/1 and IGEM/TD/13 Hydrogen Supplements and publication of the Fracture and Fatigue specification.
2. GDNs should engage with the Health and Safety Executive (HSE) to determine how HSG253 can be updated to recognise that hot tap and stoppling operations can be safely undertaken on hydrogen pipelines.
3. GDNs should consider developing a standard for carrying out hot taps and stoppling on hydrogen pipelines.
4. Updating */SP/P/9 for split tee welding for use with hydrogen pipelines.
5. GDNs should agree the criteria for girth welds of unknown quality for use in hydrogen service and consider developing a methodology and standard for their assessment.
6. GDNs should develop a standard for venting and flaring hydrogen from transmission pipelines and installations.
7. GDNs should consider developing a methodology and standard for assessing pipelines that may be affected by Internal Stress Corrosion Cracking (ISCC) following operation in manufactured gas service.
8. GDNs should adopt the Asset Compatibility Tool and ensure that it is periodically reviewed and updated to reflect current knowledge on material suitability for hydrogen service.
9. GDNs should develop a standard for inspection, assessment and repair of damaged (not leaking) hydrogen pipelines operating at pressure great than 7 bar (i.e. a hydrogen version of GN/PM/P/11).
10. GDNs should develop an approach for emergency planning hazard distances for hydrogen pipelines.
11. GDNs should review and agree the approach to the recording and retention of asset information across the full pipeline lifecycle, including design, construction, operation, surveys, diversions and investigations, to support future hydrogen suitability assessments.

2. Introduction

2.1 Background

There are two key aims of the LTS Futures Project. Firstly, to conduct a live trial and secondly to develop a "Blueprint" to assist GDNs to understand the process and steps which would be required to repurpose LTS natural gas pipelines and installations for hydrogen use. This report details the Blueprint for repurposing the LTS based on the research by the LTS Futures Project and other research projects up to the end of March 2026. There are other ongoing research projects which will further inform the requirements for repurposing LTS pipelines and installations, and as research and updated hydrogen industry standards are published the Blueprint should be updated.

The LTS Futures Project included laboratory (small-scale) and off-site (full-scale) testing in hydrogen, and a full-scale repurposing demonstration of a natural gas pipeline to hydrogen service, referred to as the "live trial". As part of the live trial this pipeline was uprated from its original operating pressure of 15 bar to 26 bar. The live trial allowed the project team to fully implement, test and further develop the repurposing process, and conduct hot tap and flow stopping trials on a hydrogen pipeline. The live trial also provided the project with the opportunity to develop and implement a "Case for Safety" and supporting procedures for the operation and maintenance of hydrogen pipelines and installations.

In addition to the live trial, several repurposing case studies were carried out on LTS pipelines and installations nominated by GDNs. These included five desktop pipeline and five installation repurposing reports (covering different ages of construction and pipeline materials) across the GDNs, with one pipeline and one installation progressing through to the live trial. The learning from these case studies was used to develop and refine the process outlined in this Blueprint.

The LTS Futures Project was delivered through several individual elements, a summary of which is given below:

1. **Live trial:**
    a. Design - repurposing study, new hydrogen supply pipe, entry points, flaring facility, odorant, gas quality facilities.
    b. Construction - new hydrogen supply pipe, entry points, flaring facility, odorant, gas quality facilities.
    c. Hydrogen supply and gas quality assessment.
    d. Assessment of fittings and equipment for use with hydrogen.
    e. Repurposing – pipeline surveys and inspections.
    f. Repurposing - modification to block valve and pig trap facility.
    g. Quantified Risk Assessment.
    h. Working Procedures/Risk Assessment/Non routine procedures.
    i. Training and competency assessment.
    j. Case for Safety.
    k. Emergency plan testing and response.
    l. Pipeline commissioning and operation with hydrogen and flow trials.
    m. Hot tap connections and flow stopping.
    n. Decommissioning.

2. **Laboratory testing (characterise three different line pipe steels taking from the LTS):**
    a. Tensile tests.
    b. Charpy V-notch tests.
    c. Hardness tests.
    d. Chemical and microstructural analysis.
    e. Threshold stress intensity factor (KIH) tests.
    f. Fracture toughness tests (still ongoing).
    g. Frequency scanning tests.
    h. Fatigue crack growth rate tests (still ongoing).
    i. Fatigue endurance tests (still ongoing).

3. **Off-site testing:**
    a. Hot works, including heat decay and welding trials, hot-tapping operations, and a fatigue test of the tees.
    b. Pipe burst and fatigue tests (the fatigue tests are still ongoing).
    c. Fatigue (vibration-induced) testing of small-bore connections.
    d. Pressure Reduction Installation testing (still ongoing).
    e. Venting and flaring.

4. **Case studies:**
    a. Pipeline repurposing case studies.
    b. Installation repurposing case studies.
    c. Capacity linepack case study.

2.2 Purpose and Scope

2.2.1 Purpose

This Blueprint outlines the principles for repurposing existing LTS pipelines and installations for hydrogen service and shares the learning generated from the LTS Futures Project, including the live trial. The Blueprint is not a repurposing specification. It is intended to inform the development of industry standards and specifications for the transmission of hydrogen through the LTS.

2.2.2 Scope

This Blueprint covers repurposing of LTS pipelines and associated installations (including block valves, pig traps and pressure reduction installations, including NTS offtakes) operated by regulated GDNs for use with hydrogen.

2.3 Characteristics of Hydrogen Relevant to Asset Repurposing

Repurposing existing natural gas assets to hydrogen service represents a complex change of gas composition. Hydrogen has measurably different physical, chemical and combustion properties which influence asset integrity, operability and risk.

In terms of material performance, hydrogen may reduce fracture toughness and ductility in certain carbon steels and may increase fatigue crack growth rates under cyclic loading. While some existing pipeline threats remain applicable, crack-like defects, fatigue and areas of stress concentration may become more significant in hydrogen service, in which case could require a change to the integrity management strategy.

The effect of hydrogen service on typical pipeline integrity threats and their susceptibility, compared to natural gas service, is shown in **Table 2.1.**

Table 2.1 Summary of Effect on Threat Identification due to Hydrogen Service

Threat	Credible	Comment	Compared to Natural Gas Service
Internal Corrosion	NO	Not credible if the hydrogen is dry.	No change
Hydrogen Induced Cracking (HIC)	NO	Not credible for hydrogen transportation (i.e. without sour gas or other source of atomic hydrogen).	No change
Internal Stress Corrosion Cracking (ISCC)	NO[1]	Not expected for pipelines with no history of towns gas service, as no credible ISCC initiation sites are present. Where towns gas service has occurred and internal cracking may exist, susceptibility to crack growth may increase under hydrogen service.	Increased (where internal cracking is present)
External Corrosion	YES	Controlled by coating and cathodic protection (CP) and monitored by overline surveys and in-line inspection (ILI).	No Change
External SCC	NO	No high temperature operation, susceptible environment, disbonded coatings or significant cyclic loading.	No Change
Manufacturing and Construction Defects	YES	Possible but will have survived the high-level hydrotest. Potential sites of fatigue crack initiation.	Increased
Fatigue	YES	Fatigue loading will need to be carefully managed and/or crack detection tools used (if available).	Increased
External Loading (Ground Movement)	YES	Dependent on susceptibility to external loads including ground movement. Areas of plastic strain will provide preferential sites for hydrogen concentrations. Reduction in elongation.	Increased
External Interference	YES	Most likely cause of failure in Western Europe. Reduction in fracture toughness and ductility, reducing tolerance to damage.	Increased

[1] Dependent on historical manufactured gas (towns gas) service and the presence of internal cracking.

From a consequence perspective, hydrogen has a wider flammability range and lower minimum ignition energy than natural gas. Ignition probability for equivalent releases is generally expected to be higher than for natural gas. See Appendix B for summary of different properties between hydrogen and natural gas. These differences do not introduce entirely new threat categories, but they can alter the credibility, frequency and consequence of existing threats. As a result, historical assessments, inspection intervals, failure frequency data and risk evaluations developed for natural gas service cannot be assumed to remain valid without review.

This Blueprint provides a structured methodology to assess:
- Material suitability and degradation mechanisms
- Changes in threat credibility and failure frequency.
- Operational risks
- Consequence and risk of failure.

Demonstrate that risk remains broadly acceptable or As Low As Reasonably Practicable (ALARP).

2.4 Abbreviations

ACT - Asset Compatibility Tool
AGI - Above Ground Installation
ALARP - As Low As Reasonably Practicable
API - American Petroleum Institute
ASME - American Society of Mechanical Engineers
ATEX - Atmospheres Explosives
Barg - Bar Pressure (gauge)
BPD - Building Proximity Distance
CAS - Competency Assurance System
CIA - Chemical Industries Association
CIPS - Close Interval Potential Survey
CO - Carbon Monoxide
COMAH - Control of Major Accident Hazards
CP - Cathodic Protection
DBB - Double Block and Bleed
DCVG - Direct Current Voltage Gradient
DMS - Dimethyl sulphide
DSEAR - Dangerous Substances and Explosive Atmospheres Regulations
DWTT - Drop Weight Tear Test
ELD - Engineering Line Drawing
ERS - Engineering Research Station
ERW - Electric Resistance Welded
EW - Electric Welded
FAT - Factory Acceptance Test
FCGR - Fatigue Crack Growth Rate
GA - General Arrangement
GDN - Gas Distribution Network
GIS - Geographic Information System
HFW - High Frequency Welded
HIC - Hydrogen Induced Cracking
HSC - Hazardous Substances Consent
HSE - Health and Safety Executive
IGEM - Institution of Gas Engineers and Managers
ISCC - Internal Stress Corrosion Cracking
LDZ - Local Distribution Zone
LEL - Lower Explosive Limit
LFL - Lower Flammability Limit
LNG - Liquefied Natural Gas
LTS - Local Transmission System
LUP - Land Use Planning
MIE - Minimum Ignition Energy
MOP - Maximum Operating Pressure
NB - New Blend
NDT - Non-Destructive Testing
NOR - Network Operation Review
NTS - National Transmission System
OEM - Original Equipment Manufacturer
P&ID - Piping and Instrumentation Drawing
PPE - Personal Protective Equipment
PRI - Pressure Reduction Installation
PSR - Pipelines Safety Regulations
PSSR - Pressure Systems Safety Regulations
QA - Quality Assurance
QRA - Quantified Risk Assessment
SAW - Submerged Arc Welded
SCADA - Supervisory Control and Data Acquisition
SCC - Stress Corrosion Cracking
SMYS - Specified Minimum Yield Strength
SOL - Safe Operating Limit
TBM - t-butyl mercaptan
UFL - Upper Flammability Limit
UK - United Kingdom
UNC - Unified Network Code
UTRS - Unified Transmission Records System
WSoE - Written Scheme of Examination

3. Requirements for Application

3.1 Repurposing Process

This Blueprint details the process required to repurpose existing natural gas pipelines and installations in the LTS to hydrogen service in accordance with the IGEM standards IGEM/TD/1 Supplement 2 [1] and IGEM/TD/13 Supplement 1 [2]. These documents are informed by ASME B31.12:2019 [3] but are adapted to be compatible with and read and applied in conjunction with IGEM/TD/1 [4] and IGEM/TD/13 [5].

This Blueprint details the current requirements for repurposing existing LTS pipelines and installations, however as the use of hydrogen is embryonic, research is continuously being published which may introduce different requirements to those detailed in this version of the Blueprint.

The repurposing process is carried out in two stages:

1. **Viability Study** – will assess whether repurposing of the buried pipeline and its associated installations is feasible. This requires assessment of design, construction and maintenance records to confirm completeness, and identification of any fundamental issue which may prevent repurposing. A key information source for the assessment is the IGEM/TD/1 MOP affirmation survey, which if of sufficient quality will provide a good assessment of a pipeline's compliance with IGEM/TD/1 Edition 6 (and is the basis of any repurposing study). The viability study will assess the impact of hydrogen on the fracture toughness and fatigue crack growth rate, identification of any change to the pipeline operating conditions, assessment of capacity, identification of population and proximity infringements which may increase the risk posed by the pipeline, the fatigue damage in natural gas service and the remaining fatigue damage available for hydrogen service. Viability studies are required for buried pipelines, above ground crossings, and for the above ground installations (AGIs), including pressure reduction installations (PRIs) and block valves, to determine whether the repurposing is feasible from a technical perspective and provide an input into the cost estimates for repurposing.

   Figure 3.1 – Summary of the Activities Carried Out as Part of the Visability Study, summarises the activities that would be carried out as part of the Viability Study.

   If the viability study shows the proposed repurposing project is both technically feasible and cost effective, then the next stage is to carry out detailed repurposing studies and modification required for hydrogen operation.

2. **Repurposing Study** – a series of detailed technical assessments and design and operability studies are required to assess the pipelines and installations for hydrogen operation. Design and operability assessments for the pipeline and installations (PRIs, metering installation and block valves) confirm compliance with the original design standard and the current edition of IGEM/TD/1 and IGEM/TD/13. Compliance with standards for design and construction is not retrospective however to repurpose for use with hydrogen, the lack of compliance with the current edition needs to be documented and assessed.

   This requires:

   a. A detailed review of compliance with the edition of the standards applied at design and construction.

   b. A comparison with the requirements of the current editions, IGEM/TD/1 Edition 6 and IGEM/TD/13 Edition 3, on which the requirements for hydrogen are based.

   c. Any non-compliances with the current standards are identified and considered in assessing the requirements for hydrogen specified in IGEM/TD/1 Edition 6 Supplement 2 and IGEM/TD/13 Edition 3 Supplement 1.

   Operability studies are required to identify any changes to operational requirements due to the change to hydrogen service, including changes to the design pressure conditions. Further work may be required to close out gaps in records and data to support the justification for repurposing for hydrogen service, this may involve material sampling or more intrusive sampling involving cutting out sections of pipeline.

   Repurposing of natural gas installations to hydrogen service shall be carried out in accordance with IGEM/TD/13 Edition 3 Supplement 1. This standard requires that the Design and Operability Assessment include assessment of condition and integrity. The design review must be carried out in accordance with i) to iii) above.

   Detailed technical studies include the specialist studies required to confirm acceptability for hydrogen service identified in the design and operability assessment for pipelines and installations for future hydrogen service. Technical studies shall be actioned if the risks posed by the pipelines and installations following the change of service from natural gas to hydrogen are acceptable.

   These studies will identify where modifications are required to permit the pipeline and installation to be used with hydrogen, these modifications will need to be completed and accepted prior to the introduction of hydrogen. The final repurposing report shall assess and document any modifications required for hydrogen operation. Note that the Cost Benefit Analysis should be updated following the repurposing study to account for the cost of the required modifications.

   Figure 3.2 – Summary of the Activities Carried Out as Part of the Repurposing Study, summarises the activities that would be carried out as part of completing the Repurposing Study and preparing the pipelines and installations for hydrogen operation.

Figure 3.1 – Summary of the Activities Carried Out as Part of the Visability Study

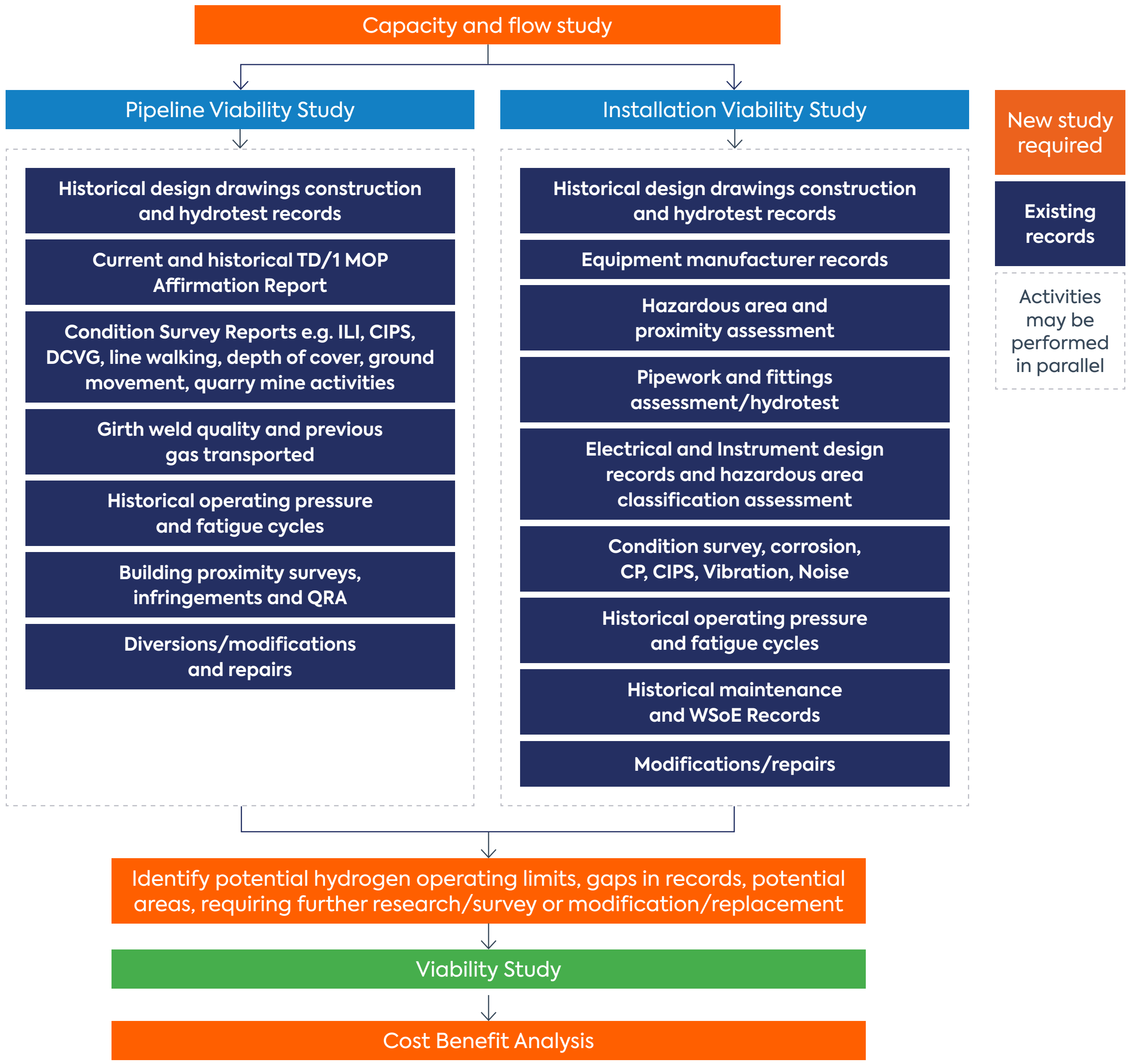
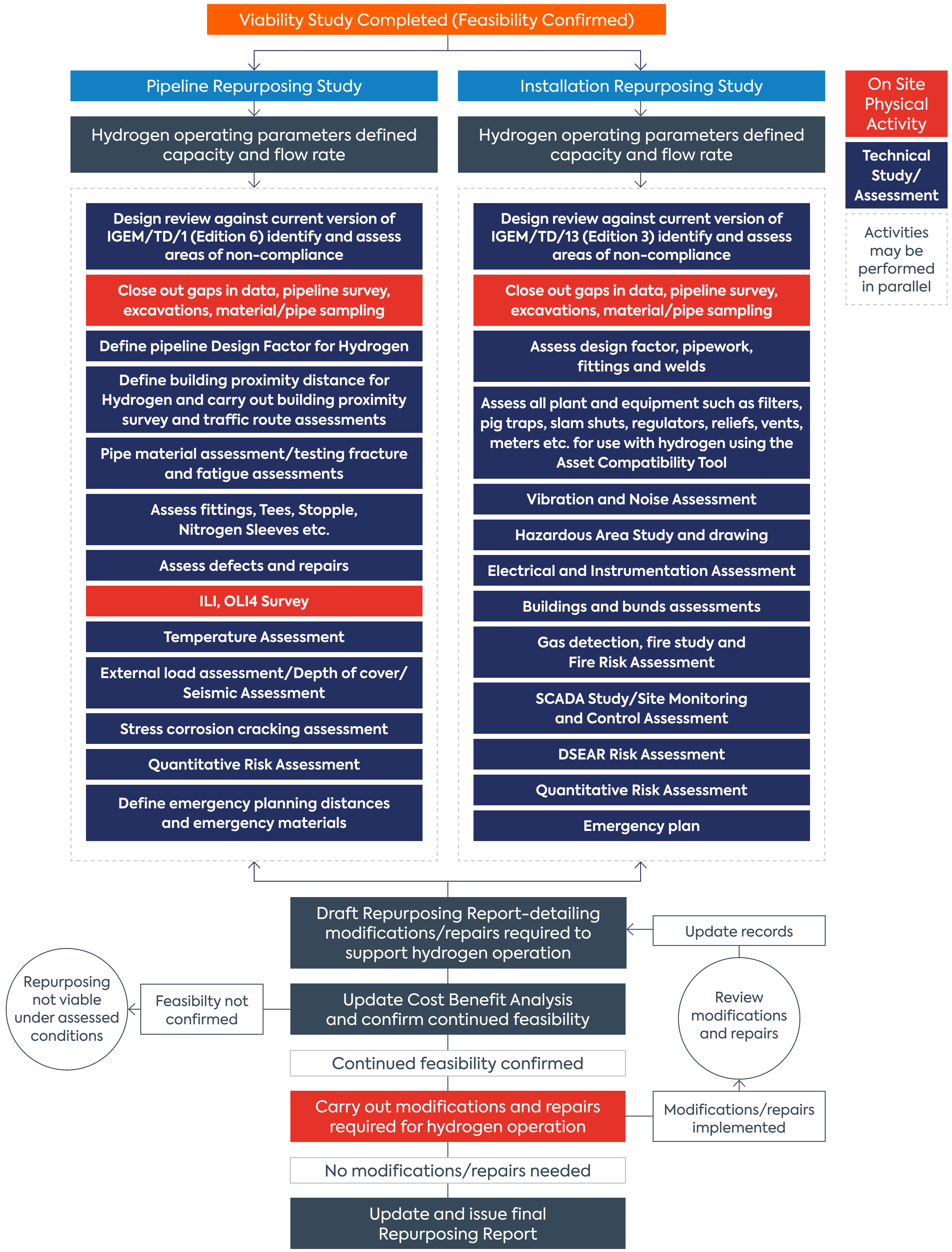


Figure 3.2 – Summary of the Activities Carried Out as Part of the Repurposing Study



3.2 Capacity Assessment

The initial capacity assessment is intended as a high-level evaluation to determine whether the existing pipeline and installations can meet the required hydrogen supply and demand. It is not intended to provide a detailed engineering verification.

Before commencing the repurposing process, the required capacity of the pipelines and installations shall be established. The calorific value of hydrogen is approximately third of natural gas therefore to supply the same amount of energy as natural gas then three times as much hydrogen will need to be transported.

The capacity of a pipeline or installation is a function of its operating pressure, flow rate and diameter, and may be influenced by operational constraints such as allowable flow velocity and pressure cycling.

There are two elements to capacity:

- Transmission capacity – which is the available capacity of the pipeline to meet downstream demand.
- Linepack– which is the storage obtainable from diurnal pressure cycling of pipelines whose capacities are not fully committed to transmission.

Linepack within the LTS is used to meet the diurnal changes in demand experienced in the distribution network, without it then additional local storage would be required to meet the within day changes in demand. If the pipeline is supplying a distribution network the capacity assessments should also consider the requirements of downstream networks operating below 7 bar.

It is not yet clear where hydrogen will be produced and stored, however it is unlikely that all the hydrogen will be produced at the same locations as natural gas enters the UK. It is more likely that hydrogen will be produced at locations where there is a surplus of electricity from wind or nuclear generation.

Whilst it is highly unlikely that the existing National Transmission System (NTS) and LTS networks will be used in the same way as for natural gas, a series of cases studies using the existing natural gas supply and demand scenarios were used to assess the impact of operating two LTS networks on hydrogen would have on the available linepack.

The network analysis studies, which were based on domestic supply/demand scenarios, were carried out on two existing LTS Networks [6] and showed that most LTS networks will require 3.2 times more storage for hydrogen to compensate for the reduction in linepack if the network was operated in the same way as for natural gas. However, as previously discussed the supply and demand requirements for hydrogen are likely to be significantly different than for natural gas and each pipeline would need to be assessed individually.

Note: *Most natural gas supplies to the UK GDNs comes from coastal entry point terminals at Easington, St Fergus, Bacton, Teesside, Milford Haven and Isle of Grain. The NTS is used to transport natural gas from these coastal terminals to the GDNs. The LTS is used by the GDNs to transport natural gas from the NTS offtakes to supply industrial, commercial and domestic demand within a GDN.*

3.2.1 Capacity and Maximum Operating Pressure (MOP)

If the pipeline capacity is sufficient to meet the hydrogen demand at its existing (or a lower MOP), then the pipeline can be considered for repurposing in accordance with section 3.

If the pipeline capacity does not meet the supply and demand requirements at its existing maximum MOP, it may be possible to increase the capacity through either:

- restore the MOP to a previous declared design pressure; or
- uprate the MOP above the original design pressure.

IGEM/TD/1 Edition 6 section 12.4 provides guidance on restoring or uprating the MOP for natural gas.

Note: *The effort required to restore an MOP within original design pressure is significantly less than that required for uprating above original design pressure.*

The pipeline MOP would need to be restored or uprated whilst operating on natural gas for a minimum of one year before being considered for hydrogen repurposing.

Before carrying out any MOP restoration or uprating for hydrogen service, a Repurposing Viability Study should be completed to determine whether any other factors would limit the pipeline MOP in hydrogen service.

3.3 Commercial Arrangements: Gas Quality and Odorisation

Initially the commercial arrangements for hydrogen pipelines are likely to be different to the complex Network Code and Entry Agreements that are used to manage supply and demand of natural gas to industrial, commercial and domestic users. The initial projects are likely to involve single hydrogen producers, with a small number of industrial/commercial users. Bespoke supply, transportation and consumption agreements are likely to be developed to meet the requirements of the Producers, Users and Pipeline Operators. The arrangements for managing hydrogen "gas" quality and metering will need to be defined and agreed with all parties.

3.3.1 Gas Quality

The gas quality will need to be specified and agreed with all stakeholders, i.e. producers, transporters, storage operators and customers. IGEM/H/1 Appendix 4 [7] provides a draft recommendation for a UK hydrogen quality standard for heat applications based on existing standards and documents. When agreeing hydrogen quality, a transporter should ensure limits on impurities which could be detrimental to pipeline integrity and/or safety. The management and analysis of gas quality will need to be agreed with all parties, along with emergency plans if the required specification cannot be met.

The requirement for odorisation shall be determined based on end-user applications and operational requirements, recognising that different users and parts of the network may have differing gas quality needs. For example, certain applications such as fuel cells may require high-purity, unodorised hydrogen, whereas domestic and commercial applications may require odorised gas for safety reasons. Consideration shall be given to how differing gas specifications are managed across the network, including the potential need for segregation of supplies or specification control at defined network boundaries.

The LTS Futures Project Network Entry Agreement detailed the entry point gas quality limits and the quality and monitoring requirements agreed between SGN and the Hydrogen Producer. The supplier could not achieve the gas quality as specified in IGEM/H/1 Appendix 4; however, because there were no downstream consumers, a reduced specification was agreed. The project developed and implemented arrangements for supplier-provided hydrogen quality monitoring with deviation reporting, supported by laboratory verification.

Note: *Research is currently being carried out to introduce a small amount of oxygen in the hydrogen being transported which may reduce certain detrimental effects of hydrogen on steel. However, any increase in oxygen content may influence flammability characteristics and associated consequence modelling and therefore requires careful safety assessment.*

3.3.2 Odorant

Hydrogen is odourless. Natural gas is odorised for safety reasons. Therefore, if the hydrogen supply is for domestic use and/or is connected to a below 7 bar network then it should be odorised to assist leak detection. However, it would not need to be odorised for transportation in a LTS pipeline.

A repurposed transmission pipeline may only supply customers who would prefer unodorised hydrogen (such as vehicle filling stations) and if they are directly connected to a transmission pipeline and operating at pressure greater than 7 bar, then the pipeline could be operated with unodorised gas.

However, if the pipeline being repurposed is to supply a below 7 bar network, then odorant should be added either at the entry into the LTS or at the entry to the below 7 bar network. Research carried out by SGN has shown that the current natural gas, Odorant New Blend (NB), would also be suitable for a hydrogen network [8].

The LTS Futures project transported both unodorised hydrogen through an 80 mm, 1 km supply pipeline and odorised hydrogen through the 450 mm, 30 km repurposed pipeline. The odorant employed was Odorant NB, which is a mixture of approximately 78% t-butyl mercaptan (TBM) and 22 % dimethyl sulphide (DMS).

At the initial stage of the repurposing project the requirement for odorised gas should be reviewed and confirmed with all customers if they are supplied directly from the LTS.

Note: *In the UK natural gas was originally odorised at the entry point to the NTS, however when the UK was connected to the European networks in 1998; odorant injection was moved to the NTS Offtakes supplying the LTS. However, natural gas transmission systems operating at pressures greater than 7 bar do not require odorisation [9]. Odorant is currently injected at the entry to the LTS because it is more efficient than installing odorant at the exit point of the LTS to the 7 bar network. Any significant leaks from transmission pipelines operating above 7 bar become evident through audible noise, gas jetting, bubbling, crater formation, and/or debris being thrown, irrespective of odorisation.*

3.4 Preliminary Cost Benefit Analysis

A preliminary cost benefit analysis should be performed before a full Repurposing Study is undertaken to ensure the repurposing costs are not prohibitive.

Consideration should be given to:

- primary benefits
- comparison of the repurposing analysis with a replacement hydrogen-ready asset. Note this is likely to be assessed as unnecessary for a pipeline due to the prohibitively high costs of replacement
- impact of inadequate records and operational data. Data availability and quality will significantly influence the ability and effort required to demonstrate integrity of the asset under the proposed repurposed operating conditions
- cost of alternative options to repurposing
- changes in risk profile and any potential risk mitigation costs.

The cost benefit analysis should incorporate secondary benefits such as life extension of the asset inherent in the repurposing and the avoidance of 'stranded' assets.

3.5 Full Lifecycle Cost Benefit Analysis

A full life cycle cost benefit analysis shall be undertaken following completion of the technical and risk assessments, and its outputs shall be incorporated into the Hydrogen Suitability Decision Report.

The analysis should:

- Incorporate capital and operational expenditure, inspection and maintenance requirements, and costs of risk mitigation measures.
- Consider avoided costs (e.g. reinforcement, replacement, or new-build infrastructure).
- Include assessment of secondary benefits such as asset life extension, alignment with decarbonisation targets, and societal/environmental impacts.
- Provide a quantified comparison of repurposing against alternative options, to demonstrate the economic justification for repurposing.

The outputs of the full cost benefit analysis form part of the evidence base for final approval of the repurposing decision.

4. Methodology for Repurposing LTS Pipelines

The repurposing methodology commences once capacity assessments in Section 2.2 are completed. An initial check should therefore confirm that the pipeline connects an identified hydrogen supply to an identified demand, and that the required throughput can be achieved at the proposed MOP.

When it is proposed to repurpose a natural gas pipeline for hydrogen service, it is necessary to:

1. **Integrity:** Demonstrate that the pipeline will retain integrity against all credible pipeline threats and load conditions under the proposed hydrogen service. This is generally achieved by showing that, following repurposing, the pipeline will comply with the design recommendations of IGEM/TD/1 Edition 6 and IGEM/TD/1 Supplement 2. The following assessments are required to demonstrate the integrity of a natural gas pipeline repurposed for hydrogen service. Further information on the methodology and requirements for each assessment provided in the indicated subsection:
   - Pipeline Records Review (Section 4.1)
   - Review of IGEM/TD/1 Maximum Operating Pressure (MOP) Audit for Natural Gas (Section 4.2)
   - Design and Operability Data Assessment (Section 4.3):
     - Original Pipeline Construction (Section 4.3.1)
     - Hydrostatic Test Assessment (Section 4.3.3)
     - Condition Monitoring (Section 4.3.4)
     - Pressure Cycling (Section 4.3.5)
     - Manufactured Gas Service (Section 4.3.6)
     - Girth Weld Quality (Section 4.3.7)
     - Detailed Technical Assessments (Section 4.4):
     - Design Factor and Material Performance Assessment (Section 4.4.1)
     - Material Testing to Assess the Effect of Hydrogen on Toughness and Ductility (Hydrogen Embrittlement) (Section 4.4.2)
     - Integrity of Fittings (Bends, Tees and Branch Connections, Flanges, Insulating Joints, Buried Valves) (Section 4.4.3)
     - Known Defects: Condition Prior to Repurposing and Future Behaviour Taking Account of Changes in Material Performance (Section 4.4.4)
     - Fatigue Assessment Including Damage to Date and Future Damage Taking Account of the Increased Rate of Crack Growth in Hydrogen (Section 4.4.5)
     - External Loads (Including Ground Movement) (Section 4.4.7)
     - Depth of Cover (Section 4.4.8)
     - Temperature (Section 4.4.9)

2. **Risk:** Confirm that the risks associated with hydrogen operation are ALARP and that conditions for repurposing are clearly defined (Section 4.5), including:
   - Updating the asset details (Section 4.6.1)
   - Confirming required modifications (Section 4.6.2)
   - Documenting risk mitigation measures and their acceptance (Section 4.6.3)
   - Addressing revalidation requirements (Section 4.6.4)

3. **Suitability for Operation:** Demonstrate that the pipeline is suitable for operation in hydrogen service (Section 4.7)

4.1 Pipeline Records Review

All available records relating to the design, construction, operation and maintenance (and decommissioning and post-decommissioning, if applicable) of the pipeline shall be obtained from the pipeline operator and receive a full review. It should be noted that diversions and/or modifications may have been made to the pipeline over the course of its operational life, resulting in records made in different time periods, under different contracts and using different specifications. The assessment should incorporate all available documentation from all pipeline sections and time periods.

The availability of adequate records is a principal requirement for repurposing a natural gas pipeline to hydrogen. The records are required to justify the repurposing process and will provide the relevant data allowing the remaining assessments in Section 4 to be completed.

Records may be primary, secondary or tertiary data sources. Primary sources represent original documentation created at the time presenting raw data on pipeline design, construction or operation. For example: as-built drawings, material test certificates, hydrotest certificates, in-line inspection reports, manufacturer datasheets, daily construction logs etc. Secondary sources are compiled, summarised or interpreted information derived from primary sources and typically created after the fact. Examples of secondary sources include fitness for purpose reports, risk assessments, MOP affirmation reports, asset registers, geographic information systems (GIS), compiled annual pressure cycle counts, other historical review reports etc. Finally, tertiary data sources are high-level overviews or reference sources, which may require assumptions or generalisations when applied to a specific pipeline, for example: industry guidance, historical standards which are assumed to apply, estimated pipeline parameters based on the year of construction, maps of the UK pipeline networks etc.

4.1.1 Management of Missing Records

The retrieval of all of the required records may at times prove to be difficult and time consuming. Information may be incomplete, missing or limited to secondary or tertiary sources. There may also be contradictory statements or discrepancies over the same type of information between different sources.

Where reliance is to be made on records other than primary data sources, where inference is required, or where a decision must be made between different sources of contradictory data; the assessor shall make an informed judgement, based on the available information, as to the adequacy and validity of the data. In all cases the judgement should be justified, stating any assumptions made and be fully documented. Any judgement should be independently validated.

For records which are missing or incomplete and the required information cannot be inferred with a satisfactory level of confidence, additional inspection or sampling and testing may be required.

4.1.2 Record Requirements

Table 4.1 identifies records which would typically be required to support the assessment of a pipeline for repurposing to hydrogen service. It should be noted that the records outlined in Table 41 do not represent an exhaustive list. Furthermore, it is also acknowledged that some of the records listed may not be available. The goal should be to construct as complete a picture as possible of the pipeline's design, construction, testing and operation, using all available supporting records. Efforts shall be made to locate, recover, and compile all records required for the assessment, including undertaking searches for physical paper documentation. The records listed in Table 41 represent the pipeline under natural gas service. Note that IGEM/TD/1 MOP Affirmation reports are a key resource for historical information to support repurposing.

Table 4.1 – Records Typically Required for Pipeline Repurposing Assessment

Record type/Requirement	Purpose/Comment
Construction and Commissioning Year	Establishes design period and applicable standards, informs likelihood of manufactured gas service, weld quality, and allows fatigue assessment to be performed.
Design Standard	Identifies the design basis and associated requirements applied at the time of construction. The applicable standard will depend on the age of the pipeline and may include current or legacy editions of IGEM/TD/1.
Design Pressure/MOP/Safe Operating Limit (SOL)	Defines the current maximum pressure for validation of repurposing (previous uprating/derating covered in operating pressure history below).
As-Built Drawings and Pipeline Route	Confirms actual layout and aids verification against design intent. Include initial as-built drawings and strip maps along with current pipeline route (satellite/coordinate data) indicating diversions; the location and design drawings of crossings and sleeves; location of protective measures such as slabbing or tape; the location and proximity to parallel pipelines; and the population along the pipeline route.
Operating Pressure History	Demonstrates current pressure containment capacity and historical pressure performance, including changes to operation, imposed restrictions or recorded pressure excursions. Include available pressure reading data with time (mid 1990s onwards) for use in fatigue analysis. Any previous pressure cycle counts, assumptions of cycle counts, or fatigue analysis reports should also be included.
Operating Temperature History	Demonstrates that the operating temperature is in accordance with the design specification and appropriate for the pipe material. Data may be taken from the outlets of appropriate installations and reporting of more general seasonal ground temperatures (Met Office, British Geological Survey, etc.). Temperature alarm history may also provide useful data.
Flowrate	Confirms the proposed flowrate for hydrogen can be achieved and compliance with gas velocity design limits. Include available historical flow rate data or estimations indicating seasonal normal rates and peak flow design value (1 in 20).
Product History	Identifies potential legacy exposure to manufactured gas and potential risk of internal stress corrosion cracking.
Modifications	Demonstrates compliance with relevant standards and traceability. Supporting evidence should include design reports, construction and commissioning records, and test results. The documentation may be held at a project level rather than a specific installation data repository.
Inspection History	Details, including frequency and associated reports, from ILI, calliper, gauge plate, CP test post, CIPS, Pearson, DCVG surveys etc. to document historical and current defects affecting the pipeline. Should also include full records of historical defect management (P/11) i.e. excavations, repairs and remediation.
Maintenance History	Demonstrates that maintenance has been completed in accordance with relevant maintenance procedures. Should include details and frequency of aerial, line-walk, vantage point, crossings, depth of cover, ground movement, seismic and external loading surveys; IGEM/TD/1 MOP Affirmation reports including any deviations or remediations.
Pipeline Design	Confirms pipeline materials, diameter, wall thickness, grade, and seam type to support hydrogen suitability. Records should include material certification and, where available, fabrication and welding details. Above-ground sections can be verified by material sampling, dimension and wall-thickness measurement, and visual inspection. Buried sections may require targeted excavation for sampling. Also include external and internal coating types; CP system type; and surveys for mining or ground movement performed pre-construction.
Girth Weld Records	Documentation relating to girth welding during construction, including welding standard, girth weld bar charts, NDT/ weld inspections, welder qualifications, consumables and field joint coating.
Fittings and Bends Records	Material and component data (number, type, manufacturer, materials). Records should include manufacturer specifications, and any associated test or inspection certificates. Details of sleeves and field bends made during construction should also be included in this category.
Hydrostatic Test Records	Confirms initial and any subsequent pressure tests (due to modifications etc.). Ideally pressure test certificates should be available. The pressure history can be used to demonstrate pressure containment to a known level.
Cathodic Protection Records	Demonstrates that the pipeline has a cathodic protection system installed, the system is compliant with maintenance procedures, and that any required remedial works have been completed.

4.1.3 Pipeline Route and History

As part of the records review, the current route of the pipeline should be accurately determined, including the start and end point locations; road, rail, watercourse, other traffic and pipeline crossings; dip points and the presence and location of any associated installations. The as-built drawings will show the original pipeline route, however numerous diversions and modifications may have occurred since commissioning, which can alter the route. Additionally, the surrounding landmarks, infrastructure, land use, and population may have changed significantly. An up-to-date corporate mapping system may provide current route coordinates; however, the accuracy of the underlying data should be confirmed by GPS linewalk or otherwise. Accurate route data is required for the quantitative risk assessment (Section 4.5) however it is also essential to determine the accuracy of above ground surveys and to correctly identify the pipeline during any excavation work (for defect validation, material sampling etc.) that may be required. It should be confirmed whether the installations associated with the pipeline are within the scope of the repurposing procedure.

A complete history of the pipeline from construction through to the present day should be established. Records are typically fragmented across multiple formats e.g. paper archives, electronic files, photocopies, and are often unsorted. Constructing a timeline permits the assessor to organise this information, identify the relationships between events and assess their cumulative impact. This approach ensures that the operational history, modifications, inspections and incidents are properly contextualised when evaluating the current pipeline integrity. To enable this, a review of historical IGEM/TD/1 reports maybe required to confirm historical changes to the pipeline.

The timeline should present the date and a brief description of each event. It should include the construction and commissioning of the pipeline and any significant events which have occurred since commissioning, e.g. changes to the product, operating pressure redeclaration, route diversions or any modifications. It should also include details of in-line inspections, excavations and repairs.

4.2 Review of Maximum Operating Pressure (MOP) Audit for Natural Gas

Affirmation of the MOP of a natural gas pipeline in accordance with IGEM/TD/1, the recognised industry standard for high-pressure gas pipelines in the UK, is a process which provides a formal assessment of the integrity of the pipeline and its associated installations, and an assessment of the risks posed on the surrounding population. The objectives are to:

- Confirm integrity
- Identify any developments in proximity to the pipeline/installations.
- Assess the population density surrounding the pipeline route and review any changes within 4 building proximity distances (BPD) of the pipeline and
- Identify any changes along the route that may impact upon the risk posed to the surrounding population.

MOP affirmation should be performed every 4 years during pipeline operation to meet the requirements of IGEM/TD/1.

The MOP affirmation process required by IGEM/TD/1 closely parallels the integrity and risk assessments required as part of the hydrogen repurposing procedure. The most recent IGEM/TD/1 MOP Affirmation report for the pipeline should therefore be reviewed. Earlier IGEM/TD/1 MOP Affirmation audits may also be referenced where they provide additional relevant detail beyond that contained in the most recent report. The MOP Affirmation report will confirm the edition of IGEM/TD/1 that the pipeline operates to, and it will provide a list of recommendations for completion to ensure the pipeline is fit to continue to operate at the declared MOP. These recommendations, together with other details from the report, will provide insight into the current integrity status of the pipeline and will inform the remaining assessments to be completed in Section 4. Issues highlighted in the IGEM/TD/1 MOP Affirmation report which are relevant to hydrogen repurposing may include, but are not limited to:

- Identification of previous manufactured gas service
- Identification of potential sub-standard weld quality
- Remediation of localised or general CP issues
- Repair of defects
- The requirement for a fatigue assessment
- Redeclaration of the MOP at a lower value
- Remediation of low depth of cover
- Requirement for risk assessment of population density and building proximity infringements
- Monitoring of areas of ground movement local to the pipeline.

If there is no IGEM/TD/1 MOP Affirmation report produced within the last 4 years available for the pipeline, then an MOP Affirmation process in accordance with IGEM/TD/1 for natural gas operation shall be performed before the hydrogen repurposing procedure.

4.3 Design and Operability Data Assessment

4.3.1 Original Construction

The original pipeline design and a complete inventory of the component parts of the original pipeline construction should be established, together with their origin and traceability, using the records compiled as part of the review in Section 4.1. The purpose of the assessment is to provide input data primarily for subsequent assessments to determine the suitability of the pipeline materials and fittings. The data will also inform the remainder of the assessments in Section 4.

The original design code and the current code to which the pipeline is operated and maintained should be confirmed. This will typically be the current or a legacy edition of IGEM/TD/1, going back to the original Communication 674 published in 1965. The publication dates for previous editions of IGEM/TD/1 are:

- Communication 674 (1965) "Recommendations Concerning the Installation of Steel Pipelines for High-Pressure Gas Transmission" [10].
- IGE/TD/1: Edition 1 (Communication 674 ABCD) (1977) "Steel Pipelines for High Pressure Gas Transmission" [11].
- IGE/TD/1: Complete Edition 2 (Communication 1234) (1984) "Steel Pipelines for High Pressure Gas Transmission" [12].
- IGE/TD/1: Edition 3 (Communication 1530) (1993) "Steel Pipelines for High Pressure Gas Transmission" [13].
- IGE/TD/1: Edition 4 (Communication 1670) (2001) "Steel Pipelines for High Pressure Gas Transmission [14].
- IGEM/TD/1: Edition 5 (Communication 1735) (2008) "Steel Pipelines for High Pressure Gas Transmission" [15].
- IGEM/TD/1: Edition 6 (Communication 1848) (2021) "Steel Pipelines for High Pressure Gas Transmission".

The original design pressure, the current declared operating pressure and any changes to the declared operating pressure which have occurred since commissioning should also be confirmed.

Line pipe specifications and properties should be confirmed for all line pipe used in construction of the pipeline, including:

- Outside diameter(s) and wall thickness(es)
- Material specification (API 5L, EN 10208, ISO 3183)
- Grade and manufacturing type (LSAW, HFW, seamless etc.)
- Chemical composition
- Mechanical properties (yield strength, tensile strength, Charpy v-notch energy, carbon equivalent values, elongation, hardness)
- NDT and hydrostatic test results
- Manufacturer and date of manufacture.

This information may be found on the Material Test Certificates. Other documents such as purchase orders and material registers will provide additional traceability and verification of the design requirements. Similarly, the specification and properties should be confirmed for the full inventory of pipeline fittings (bends, tees, flanges, weldolets, sweepolets, caps etc.) used in the construction of the pipeline. Fittings require the same material and manufacturing data to be confirmed as for line pipe, however additional required information specific to fittings includes:

- Fitting type
- Size
- Pressure rating/class
- Manufacturing standard (ASME B16.9, B16.5, MSS-SP-75, */SP/F/1, */SP/F/4 etc.).

As with line pipe this data may be found on the Material Test Certificates.

For all valves which are considered part of the pipeline (versus an installation) confirmation should be made of the:

- Manufacturer
- Model number
- Valve type (gate, ball, check etc.)
- Size
- Pressure rating.

For nitrogen filled sleeves on the pipeline (protective casings at crossings) the design specifications, construction details, as-built drawings, location and materials used for each sleeve should be confirmed.

As noted in Section 4.1, pipeline records may be missing or incomplete. For line pipe, missing information can potentially be determined through reference to alternative secondary sources such as obsolete database repositories including the Unified Transmission Records System (UTRS) database and/or the Engineering Research Station (ERS) database. It may also be possible to infer lower bound values for missing material properties if information such as the material specification is known. However, it should be noted that upper limits apply to material grade for hydrogen pipeline operation (see Section 4.4.1) and the properties of line pipe often exceed the quoted specification. Caution should be applied if assumptions are to be made without confirmation of the material properties. The use of any information taken from non-primary sources should be documented.

Any inconsistencies identified across available sources relating to the line pipe, fittings, valves or sleeves should be documented. Inconsistencies associated with the line pipe seam weld type may potentially be resolved by cross-referencing with the edition of TD/1 appropriate to the pipeline construction, recent editions (Editions 4, 5 and 6) of which contain a table indicating methods of pipe manufacture and the normally available pipe sizes associated with each.

As previously noted, informed judgement based upon the available information should be made where required when information associated with a degree of uncertainty is to be used in further assessments. Any assumptions made should be stated with justification. Any judgement should be independently validated.

Where the available information is insufficient to derive reasonable conclusions regarding the design and materials used for the line pipe, fittings, valves and nitrogen sleeves, it is required that excavation and sampling is performed and that the samples are tested in accordance with the documents indicated in Section 4.4.2.

Further details on line pipe acceptability and material testing are provided in Section 4.4.2.
Further details on the acceptability of fittings, valves and nitrogen sleeves are provided are Section 4.4.3.

4.3.2 Modifications and Diversions

The design and a complete inventory of the component parts of all pipeline modifications and diversions should be established, together with their origin and traceability, using the records compiled as part of the review in Section 4.1. The purpose of the assessment is to provide input data to determine the suitability of the materials and fittings used in the modifications and diversions. The data will also inform the remainder of the assessments in Section 4.

The category of modifications and diversions primarily relates to diverted, extended or re-laid sections of the original pipeline, but can include the addition or replacement of valves, upgrades to the pipeline CP system, modification of sleeves, hot-tap connections etc. Replacement of pipeline sections is treated as a modification under this section. Repair activities are excluded and are addressed separately in Section 4.4.4.

The quantity, location, type and date of installation for all modifications and diversions on the pipeline should be confirmed. For modifications and diversions involving the introduction of new line pipe, the length and route of each new section should also be confirmed.

The design specifications, construction details, as-built drawings and materials used for each modification and diversion should be confirmed. It should also be confirmed if any permanent changes to pipeline operation were made following installation of the modification or diversion, e.g. limits on operating pressure.

For new line pipe, specifications and properties should be confirmed for all of the pipe used in construction of the modification or diversion. The same material and manufacturing data is required as listed for line pipe in Section 4.3.1. This information may be found on the Material Test Certificates. Other documents such as purchase orders and material registers will provide additional traceability and verification of the design requirements.

Similarly, the specification and properties should be confirmed for the full inventory of pipeline fittings (bends, tees, flanges, weldolets, sweepolets, caps, hot-tap connections etc.) used in the construction of the modification or diversion. Fittings require the same material and manufacturing data to be confirmed as listed for fittings in Section 4.3.1. As with line pipe this data may be found on the Material Test Certificates.

For all valves which are added as part of modifications or diversions, confirmation should be made of the same information as listed for valves in Section 4.3.1.

For nitrogen sleeves the same information is required for each sleeve as listed for sleeves in Section 4.3.1.

For line pipe it may be possible to infer lower bound values for missing material properties if information such as the material specification is known. However, it should be noted that upper limits apply to material grade for hydrogen pipeline operation (see 4.3.1) and the properties of line pipe often exceed the quoted specification. Caution should be applied if assumptions are to be made without confirmation of the material properties. The use of any information taken from non-primary sources should be documented.

Any inconsistencies identified across available sources, relating to the modifications and diversions should be documented. Inconsistencies associated with line pipe seam weld types may potentially be resolved by cross-referencing with the edition of TD/1 appropriate to the pipeline construction, recent editions (Editions 4, 5 and 6) of which contain a table indicating methods of pipe manufacture and the normally available pipe sizes associated with each. However, the possibility of deviations applied during construction should be considered.

Informed judgement based upon the available information should be made where required when information associated with a degree of uncertainty is to be used in further assessments. Any assumptions made should be stated with justification. Any judgement should be independently validated.

Where information is missing or the available information is insufficient to derive reasonable conclusions regarding the design and materials used for a given modification or diversion it is required that excavation and sampling is performed and that the samples are tested in accordance with the documents indicated in Section 4.4.2.

Further details on line pipe acceptability and material testing for modifications and diversions are provided in Section 4.4.2. Further details on the acceptability of fittings, valves and nitrogen sleeves associated with modifications and diversions is provided in Section 4.4.3.

4.3.3 Hydrostatic Test Assessment

In accordance with IGEM/TD/1 Edition 6 and IGEM/TD/1 Supplement 2, pipelines must be hydrostatically tested before commissioning[2].

For pipelines designed to operate at a design factor exceeding 0.3 the test must be to the first occurring of the levels indicated for both the pre-installation and the main test in Table 4.2. The test requirements however may be relaxed to a pressure of 1.5 x MOP if the daily variation in hoop stress does not exceed 35 Nmm^{-2} or a detailed fatigue assessment shows that the required design life is achieved.

Table 4.2 – Hydrostatic Test Requirements for Pipelines Designed to Operate at a Design Factor Exceeding 0.3

Seam Welded Pipe (Saw)		Seamless Pipe		Seam Welded Pipe (ERW/HFW)	
Pre-Installation	**Main Test**	**Pre-Installation**	**Main Test**	**Pre-Installation**	**Main Test**
a) Design factor of 1.1 or, b) Half-slope on P/V plot.	a) Design factor of 1.05, b) Half-slope on P/V plot or, c) Max. pressure in pre-installation test	a) Design factor of 1.0 or, b) Half-slope on P/V plot	a) Design factor of 0.9, b) Half-slope on P/V plot or, c) Max. pressure in pre-installation test	a) Design factor of 1.05 or, b) Half-slope on P/V plot	a) Design factor of 1.0, b) Half-slope on P/V plot or, c) Max. pressure in pre-installation test

For pipelines or diversions designed to operate at a design factor not exceeding 0.3 the hydrostatic test shall be to a pressure of (1.05 x MOP) + 10 % for the pre-installation test and 1.5 x MOP for the main test, except when subject to daily stress cycles exceeding 35 Nmm^{-2}. If the daily stress cycling is to exceed 35 Nmm^{-2} then the test level should instead be determined by a fatigue assessment. A fatigue assessment may also be used to relax the pressure test requirement of 1.5 x MOP if it is shown that the required design life due to pressure cycling is achieved for a lower test level.

When considering a diversion which has a design factor not exceeding 0.3 which will form part of an existing pipeline designed to operate at a design factor above 0.3, then the test pressure of the diversion shall be set at the test pressure of the existing pipeline, or if this is not known, calculated using the wall thickness, material SMYS and outside diameter of the existing pipeline.

It should be confirmed using available records that the pre-commissioning hydrostatic test pressure for all sections of the original pipeline and any diversions or modifications involving new sections of line pipe, satisfy the requirements of IGEM/TD/1 Edition 6 and IGEM/TD/1 Supplement 2. Compliance with these standards should also be confirmed for any additional hydrostatic testing performed post-commissioning. It should be noted that data concerning daily pressure cycling may be required to determine if the testing was appropriate. Pressure cycling is considered in Section 4.3.5.

[2] Note that pipelines which are being repurposed to hydrogen from natural gas do not require a hydrotest. A hydrotest will have been performed prior to the pipeline being commissioned for natural gas.

Where required the design factor shall be calculated using the equation:

$$f = \frac{P_t D}{20 t_{nom} \sigma_Y}$$

Equation 4.1

Where f is the design factor, P_t is the hydrostatic test pressure, D is the outside diameter of the pipe section in mm, t_{nom} is the nominal wall thickness of the pipe section in mm and σ_Y is the SMYS of the pipe material in Nmm^{-1}.

It should be noted that sections with different wall thicknesses may have received different test pressures and therefore care should be taken to ensure that all sections tested and all test pressures used are considered.

Any deviations or non-conformances associated with the test procedures or requirements, including concessions and waivers, should be documented along with their justification. For example, violation of the maximum altitude variation over the length of the test section requirement of 60 m. IGEM/TD/1 permits relaxation of this requirement provided it can be demonstrated that over or under stressing of the test section does not occur at the elevation extremes.

Ideally the hydrostatic test pressures used will be available on the original test certificates, however if these are missing alternative sources which may provide the information include: pipeline design, construction and commissioning documentation, historical correspondence with regulators, regulatory submissions (pipeline notification etc.), as-built drawings, the UTRS or ERS databases, and MOP affirmation reports.

The use of any information taken from non-primary sources, and any inconsistencies identified across available sources, relating to the hydrostatic test pressures should be documented. Informed judgement based upon the available information should be made where required when information from secondary or tertiary sources or information associated with a degree of uncertainty is to be used. Any assumptions made should be stated with justification.

The hydrostatic test pressures are used as part of the fatigue assessment in Section 4.4.3

4.3.4 Condition Monitoring

A complete history of all condition monitoring surveys the pipeline has received should be established using the records compiled as part of the review in Section 4.1. The purpose of the assessment is to determine how the condition of the pipeline has changed over the course of its operational life and to provide input data for the subsequent pipeline defect assessments in Section 4.4.4.

It should be determined whether the pipeline is "OLI/1" and able to be internally inspected or "OLI/4" and subject to above ground surveys only. If the pipeline is not able to be internally inspected the reasons for this should be confirmed. An IGEM/TD/1 MOP Affirmation report to the requirements of Edition 6 should confirm this information as part of the audit procedure in accordance with clause 12.4.2.6.

For OLI/1 pipelines a complete history of all in-line inspections which have taken place should be established. For each inspection confirmation should be made of the:

- Type of inspection (MFL-A, MFL-C, EMAT, Calliper etc.)
- Inspection date
- Inspection vendor and tool(s) used
- Findings of each inspection (number, type and severity of the reported features, whether growth was found etc.)
- Issues associated with the inspection (velocity excursions, data corruption, data quality etc.)
- Actions following the inspection (repairs, excavations etc.).

For actions taken following the inspection the location and type of the repairs should be confirmed. If no action was taken following an inspection the reasons for this should be confirmed.

Primary data sources for in-line inspections will be the preliminary and full inspection reports produced by the inspection vendor, and any follow up fitness-for-purpose reports. Primary records should also be available separately for any repairs, including completed UKOPA FR/1 forms. Secondary data sources for inspections and repairs include IGEM/TD/1 MOP Affirmation Reports, the UKOPA Fault Database and internal network work and asset databases.

For OLI/1 and OLI/4 pipelines the most complete history possible, based on available records, of above ground surveys which have taken place should be established. For each survey confirmation should be made of the:

- Type of survey (CP test post, CIPS, DCVG, Pearson etc.)
- Survey date
- Survey vendor
- Findings of each survey (number, type of reported features etc.)
- Issues with the survey (Incomplete surveys, missing posts, access issues, stray currents detected etc.)
- Actions following the survey (repairs, excavations etc.).

Details of localised surveys performed separately, for example visual surveys at above ground watercourse crossings should also be included.

Maintenance activities for the pipeline CP system should be established such as the replacement of anode beds or installation of new groundbeds by reviewing CP records and databases.

The condition maintenance history for all valves which are considered part of the pipeline (versus an installation), both on original pipeline sections and any modifications or diversions, should be established, indicating when inspections were performed, the findings of each inspection and any remedial actions.

It should be established if there are any gaps in the condition monitoring history, either missing data for inspections/surveys which were performed or periods where no surveys were performed when they otherwise would have been required. If there is no up to date inspection data (for OLI/1 pipelines), above ground survey data (for OLI/4 pipelines), watercourse crossings inspections or condition data for any given valve on the pipeline then it is required that the relevant inspections are performed in order to increase understanding as to the current pipeline condition and provide input data for the defect assessments in Section 4.4.4.

The use of any information taken from non-primary sources, and any inconsistencies identified across available sources, relating to condition monitoring should be documented. Informed judgement based upon the available information should be made where required when information from secondary or tertiary sources or information associated with a degree of uncertainty is to be used. Any assumptions made should be stated with justification. Any judgement should be independently validated.

4.3.5 Pressure Cycling

The complete pressure cycling history of the pipeline should be established using the records compiled as part of the review in Section 4.1. The purpose of the assessment is to provide input data for the fatigue assessment in Section 4.4.5.

The number of pressure cycles completed by the pipeline from commissioning to present day, for all periods of operation should be confirmed. This should indicate the annual number of cycles and the size of each cycle. The data may be in the form of raw pressure/time data (values recorded per minute, hour etc.) and/or in summary spreadsheets or reports presenting annual or cumulative counts. For summary data it should be determined whether cycles below 35 Nmm^{-2} are included in the cycle counts. A summary of pressure cycling is typically included in the IGEM/TD/1 MOP affirmation reports. Raw pressure/time data is the preferred data source for the repurposing procedure as this permits an accurate count (rain flow, reservoir etc.) of the pressure cycles to be performed. However, it is acknowledged that recording of this information will have only started circa the 1990s and that a limited amount of data may be stored. Data from the most recent 5 years of operation is considered to be sufficient to assist confirmation of older summarised data.

It should be determined whether any historical fatigue analysis studies have been performed and if the pipeline has a reduced fatigue design life (<15,000 cycles of 125 Nmm^{-2}) resulting, for example, from a reduced pre-commissioning hydrostatic test pressure.

The absence of any data it should be documented whether this is because data is not available or because pressure cycling is not recorded for the pipeline due to it being below 35 Nmm^{-2} and therefore not required by IGEM/TD/1. Furthermore, any indications of uncertainty in the available data should be documented, for example any assumptions made over historic pressure cycle counts to account for missing data.

The use of any information taken from non-primary sources, and any inconsistencies identified across available sources, relating to pressure cycling should be documented. Informed judgement based upon the available information should be made where required when information from secondary or tertiary sources or information associated with a degree of uncertainty is to be used. Any assumptions made should be stated with justification. Any judgement should be independently validated.

4.3.6 Manufactured Gas Service

Where there is evidence or credible possibility that a pipeline has transported manufactured gas prior to conversion to natural gas, the potential for internal stress corrosion cracking (ISCC) shall be assessed.

Where it can be demonstrated that the pipeline has not transported manufactured gas, ISCC is not considered a credible threat, and no further assessment is required.

Further background and guidance can be found in Appendix D.

4.3.7 Girth Weld Quality

Girth weld quality of the original pipeline and any subsequent modifications or diversions shall be established through records review.

Assessment shall consider:

- Construction date relative to the introduction of 100 % radiography and GIS/P2 inspection requirements
- Availability of welding procedures, welder qualifications and inspection records
- Post-commissioning girth weld defects or failures
- Results of any in-service inspections or excavations.

Where records are incomplete, construction predates 100 % radiography, or inspection history indicates potential concerns, further assessment or inspection shall be undertaken. Appendix E contains further Girth Weld Quality guidance.

Where records demonstrate compliance with applicable standards at the time of construction and no adverse inspection history is identified, girth weld quality may be considered adequate.

4.4 Detailed Technical Assessments

4.4.1 Design Factor and Material Performance Assessment

It should be confirmed that the design factor of the pipeline in hydrogen service satisfies the requirements of IGEM/TD/1 Supplement 2. Pipeline design factor may be calculated using the equation:

$$f = \frac{PD}{20 t_{min} \sigma_Y}$$

Equation 4.2

Where f is the design factor, P is the proposed maximum operating pressure of the pipeline in hydrogen service in barg, D is the outside diameter of the pipeline in mm, t_{min} is the minimum pipeline wall thickness (nominal less under-tolerance) in mm and σ_Y is the specified minimum yield stress (SMYS) of the pipe steel in Nmm^{-2}.

In accordance with IGEM/TD/1 Supplement 2, the maximum allowable design factors for pipelines in hydrogen service, operating in rural (R) areas, are shown in Table 4.3. In Table 4.3 the maximum design factor is limited based on the grade of the pipe steel.

Table 4.3 - Maximum Design Factor, Rural Areas, IGEM/TD/1 Supplement 2

Material Grade	Maximum Design Factor	Material Performance Factor (h)
L360/X52 and below	0.5	1.0
L415/X60	0.43	0.87
L450/X65	0.4	0.8
L485/X70	0.37	0.74

For pipelines in hydrogen service located in suburban (S) areas, the maximum allowable design factor is normally 0.3. The limits from Table 4.3 may only be applied in S-areas if the section in question has a wall thickness of at least 19.1 mm.

From Table 4.3 the maximum design factor of pipelines in hydrogen service is 0.5 (as compared to 0.72/0.8 in natural gas service). A material performance reduction factor, as defined in ASME B31.12 [3], is applied to reduce the allowable design factor for grades higher than L360 (X52). It should be noted that alternative approaches to the use of a material performance reduction factor are under development [16, 17]. A review of recent publications should be performed to ensure compliance with current industry guidance.

For pipelines in R areas the design factor calculated using Equation 4.2 should be below the value in Table 4.3 corresponding to the grade of the line pipe material. For pipelines in S areas the design factor calculated using Equation 4.2 should be below a value of 0.3 unless the minimum pipeline wall thickness is at least 19.1 mm. If the minimum wall thickness of an S area pipeline is at least 19.1 mm, then the design factor calculated using Equation 4.2 should be below the value in Table 4.3 corresponding to the grade of the line pipe material.

Note that the requirements of the above paragraph should apply for the entire pipeline route. Therefore, where the pipeline contains sections with different values of wall thickness or different material grades (for example as part of modifications or diversions), or where the pipeline route is located in both R areas and S areas, then the design factor should be calculated for each distinct section and the appropriate area-specific requirements applied.

Pipelines in S areas will, by default, meet the specified design factor requirements except for grades L415 and higher when line pipe with a wall thickness greater than or equal to 19.1 mm has been used. Pipelines in R areas will, by default, not meet the specified design factor requirements.

If a pipeline is located in an H area, then the design factor in hydrogen should be assessed by performing a risk assessment in accordance with the requirements of Section 4.5.4.

If any of the calculated design factors for the pipeline route exceed the limits specified, then the proposed operating pressure for the pipeline in hydrogen service shall be reduced to a value for which all design factors satisfy the requirements. Alternatively, a more detailed fitness-for-purpose assessment including material qualification should be completed to assess the acceptability of repurposing the pipeline to hydrogen service.

4.4.2 Material Qualification Testing

Hydrogen embrittlement is a broad term that describes a variety of different but related degradation mechanics affecting certain materials. For pipeline operation, it is required that all pipe material has sufficient energy absorption to ensure resistance to fracture initiation and propagation at the minimum design temperature. It is therefore required that pipeline materials are classified as acceptable for hydrogen service.

All of the line pipe materials used in the original construction of the pipeline, identified in Section 4.3.1, and any modifications or diversions, identified in Section 4.3.2, should be assessed for acceptability for hydrogen service. An assessment may involve excavation, sampling and testing, with testing performed in accordance with the documents indicated below; and confirmation that the line pipe matches pipe of a particular specification, see overleaf.

IGEM/TD/1 Supplement 2 states that a material may be qualified for hydrogen service by laboratory or demonstration scale testing, or field experience, with laboratory-scale testing required to determine the acceptability of the material fracture toughness in hydrogen; and the effect of hydrogen on the fracture propagation transition temperature and the upper shelf Charpy v-notch impact energy. It also requires that for line pipe of diameter exceeding 323.9 mm, a full wall thickness drop weight tear test (DWTT), performed at a temperature of 0°C or the minimum design temperature, whichever is lower, should be applied to characterise the resistance to propagating brittle fractures. The supplement includes several requirements, listed below, for pipe materials to be considered acceptable for hydrogen service and indicates these requirements may be relaxed if laboratory-scale testing shows the materials to be acceptable:

- For the line pipe specification, the carbon equivalent of the steel should not exceed 0.43.
- For the line pipe specification, the hardness should be limited to HV250[3].
- For line pipe strength grade, grades higher than L485 (X70) should not be used.
- For line pipe strength, the maximum tensile strength of the pipe and the weld metal should not exceed 690 Nmm^{-2}.

Additionally, the supplement requires that consideration be given to the possibility of hydrogen induced cracking (HIC).

The specific implications of the requirements of IGEM/TD/1 Supplement 2 should be considered; however a number of simplifications may be made.

Line pipe steel specified to API Specification 5L, inclusive of the sixteenth (April, 1969) and subsequent editions of API STD 5LX, may be assumed, in principle, to be partially-qualified for hydrogen service. The intent of a "partially-qualified" classification is to reduce the requirements for testing that does not add value. It is based on the observation that line pipe steel is not susceptible to environmental cracking when exposed to gaseous hydrogen. The question of qualification then becomes one of a combination of load, geometry and material properties, specifically toughness. The sixteenth edition of API STD 5LX introduced the supplementary requirements for Charpy v-notch impact energy and DWTT. Consequently, it has been recommended as a cut-off point for partially-qualified line pipe. Pipelines constructed using line pipe specified to earlier editions of API STD 5LX may potentially be partially-qualified by establishing what was or was not specified by the earlier edition and considering the associated implications for hydrogen service.

Low frequency electric welded (EW) (also referred to as electric resistance welded (ERW)) line pipe is known to have the potential to be problematic. Specifically, it may be associated with significant seam weld defects, low seam weld and HAZ toughness and high residual welding stresses. It therefore may not be assumed to be partially-qualified. The approach to partially-qualify a specific pipeline constructed using low frequency EW line pipe would be to first establish whether the pipe is problematic. It would then be necessary to establish the effect of hydrogen on the properties of the seam weld, and the implications of that on the pipe.

Butt or lap-welded line pipe is not acceptable for hydrogen service.

For material which is assumed to be partially-qualified for hydrogen service, the yield and tensile strength may be assumed to be unaffected when exposed to gaseous hydrogen (and assuming operating conditions typical of the Local Transmission System). The specified tensile properties, commensurate with the grade, may be used. However, the effect of exposure to gaseous hydrogen on the fracture toughness and the rate of fatigue crack growth will need to be considered for the proposed operating conditions.

[3] Ongoing work is expected to further inform acceptable limits. The specified hardness limit may therefore be conservative.

Line pipe of grades L450 (X65) and below may be assumed to be qualified for hydrogen service if the material performance factor from Table 43 is applied and the lower bound fracture toughness indicated below is used.

Additionally, in the absence of data (or other contrary indications)[4], if the material performance factor from Table 43 is applied and the lower bound fracture toughness indicated below is used:
The requirements on carbon equivalent and hardness from IGEM/TD/1 Supplement 2 indicated above may be assumed to be met.

The requirements on the tensile strength of the pipe and weld metal from IGEM/TD/1 Supplement 2 indicated above may be assumed to be met for grades L360 (X52) and below.

Tensile testing in hydrogen should be conducted in accordance with BS EN ISO 6892-1.

The fracture toughness may be determined by fracture toughness testing in hydrogen, or an appropriate lower bound fracture toughness (indicated below) may be used. However, endurance or fatigue crack growth rate testing is not required, see Section 4.4.5. The effect of exposure to gaseous hydrogen on the ductility (the percentage elongation at fracture) will need to be considered if a strain-based approach is to be used to assess dents, see Section 4.4.4. The ductility may be determined by tensile testing in hydrogen, or an appropriate lower bound percentage elongation at fracture may be used. Confirmation of an appropriate lower bound value would require a review of data from tensile tests in hydrogen undertaken by the GDNs (and National Gas).

Fracture toughness testing in hydrogen should be conducted in accordance with ASTM E1820 [18] or BS ISO 12135 [19], informed by ANSI/CSA CHCM-1 [20] and the EPRG Draft best practice guidelines for small scale fracture toughness testing in hydrogen gas of carbon steel pipeline material [21].

Fracture toughness testing is not required if the material performance factor from Table 43 is applied and a lower bound fracture toughness (indicated below) may instead be assumed. It should be noted however that assuming a lower bound fracture toughness may have implications for fatigue life and defect acceptability in hydrogen service.

Operators are recommended to conduct fracture toughness testing in hydrogen in order to produce a broad set of representative data. It is also recommended that an appropriate lower bound value is derived from a review of all fracture toughness testing that has been (or will be) undertaken by the GDNs (and National Gas), and correlation of that test data with other material properties such as yield or tensile strength, or hardness.

A fracture toughness equal to 27.5 MPa.m0.5 (869.6 $N.mm^{-3/2}$) may be used as a conservative lower bound in the absence of relevant test data. This value is half of the minimum acceptable value of 55 $MPa.m^{0.5}$ given in ASME B31.12-2023. It is emphasised that the value of 55 $MPa.m^{0.5}$ stated in ASME B31.12 is not the minimum possible fracture toughness of line pipe steel in hydrogen, it is a minimum acceptance criterion ("In any case, K_{IH} shall not be less than 50 [$ksi.in^{0.5}$]"). A safety factor of two is applied, with the intention of defining a conservative lower bound value to be used in the absence of relevant test data. The resulting value of 27.5 $MPa.m^{0.5}$ is conservative relative to the fracture toughness testing conducted under LTS Futures.

[4] Contrary indications include the following as indicated by pipeline records: failures during the pre-commissioning hydrostatic test, failures due to manufacturing defects, failures due to poor quality girth welds, failures due to (internal) stress corrosion cracking, any section of the pipeline is suspected of having poor quality girth welds, any section of the pipeline is suspected of having (internal) stress corrosion cracking, any section of line pipe was constructed using low frequency electric resistance welding, the pipeline has had its maximum operating pressure reduced because of a high transition temperature, or, any section of line pipe is known or suspected to have a fracture toughness which would be considered unacceptable in accordance with the requirements of IGE/TD/1 Edition 2.

Note that Clause S5.3.4.11 in Supplement 2 states that, in the absence of testing, the fracture toughness in hydrogen service may be estimated using the Charpy V-notch impact energy. This approach is not recommended.

The possibility of HIC may be assumed to be negligible.

If the line pipe from the original pipeline and/or modifications/diversions cannot be classified as acceptable for hydrogen service using the simplifications indicated above, then material qualification in accordance with IGEM/TD/1 Supplement 2 should be completed to assess the acceptability for hydrogen service.

4.4.3 Integrity of Fittings

As with the pipe material, fittings operating in a hydrogen environment are also susceptible to hydrogen embrittlement. In accordance with IGEM/TD/1 Edition 6 and IGEM/TD/1 Supplement 2 it is required that all pipeline fittings used in the original construction of the pipeline, identified in Section 4.3.1, and any modifications or diversions, identified in Section 4.3.2, are classified as acceptable for hydrogen service. In addition to standard components such as forged bends and tees, fittings, in this context includes valves, sleeving and any associated sleeve end seals.

IGEM/TD/1 Supplement 2 includes the requirement that the hardness of fittings should be limited to 250 HV10. Additionally, the Supplement includes several requirements, listed below, for valves and actuators to be considered acceptable for hydrogen service:

- Valves and actuators should be double block and bleed, single block and bleed with positive isolation.
- Each valve/actuator body should be hydraulically leak tested.
- In-line automatic valves and automatic vents should have soft seats in a metal retainer and specify bubble tight shut off.
- In-line manual valves should have metal to metal seats or soft seats in a retainer; these should be combined with a means of positive isolation if used to block the flow path before attempting invasive maintenance or inspection inside the pipeline.
- Each valve/actuator should have a metallic seat with valve outlet blocked.
- Valves/actuators should minimise through bolting, body flanges or threaded in assembly of the body of the valve unless the gaskets are suitable for hydrogen service.

Hydrostatic leak testing of fittings and valve/actuator castings provides assurance of pressure containment at the time of test. However, it should be recognised that such testing does not fully characterise defect tolerance for hydrogen service. Due to the potential reduction in fracture toughness and increased crack growth rates in hydrogen environments, defects that are acceptable in natural gas service may not remain tolerable. Where fittings incorporate cast components, consideration should be given to the quality assurance applied during manufacture and the potential for internal defects. Additional inspection, testing or conservative assessment may be required where this cannot be demonstrated.

Fittings should be qualified for hydrogen service by laboratory or demonstration scale testing or application of the Asset Compatibility Tool (ACT – see Appendix C). Note that all the fitting requirements from IGEM/TD/1 Supplement 2 may be relaxed if laboratory-scale testing shows the fittings to be acceptable.

If the fittings from the original pipeline and/or modifications/diversions cannot be classified as acceptable for hydrogen service, then material qualification in accordance with IGEM/TD/1 Supplement 2 should be completed to assess the acceptability for hydrogen service.

4.4.4 Defects

In accordance with IGEM/TD/1 Supplement 2, all existing pipeline defects, identified through condition monitoring or hypothesised, should be confirmed to be acceptable for hydrogen service through detailed technical assessments. Furthermore, where a defect has previously been repaired, it should be checked that the repair is also acceptable for hydrogen service. Assessments should address the future behaviour of the defects/repairs, taking into account the effects of hydrogen on material properties.

Workmanship defect acceptance levels associated with the line pipe and fittings from the original pipeline and modifications/diversions should also be demonstrated to be acceptable under hydrogen service. The level of detail required to demonstrate this acceptability will be less if the material performance factor from Table 4.3 is applied and if fatigue loading is low. It is recommended that a generic assessment is developed for the acceptability of workmanship defect levels so that in the vast majority of cases, it is not necessary to conduct a specific assessment.

All of the in-line inspection reports for the pipeline identified in Section 4.3.4 should be reviewed. The date and type of the inspection (MFL, EMAT, Calliper, etc.) and the inspection tools used should be established. For each inspection the following data should be confirmed:

- The number of defects reported
- The type (corrosion, milling metal loss, construction metal loss, dent, gouge, etc.) of each defect
- The reported dimensions (length, width, depth) of each defect (and any associated inspection tool tolerances)
- The location of each defect along the length of the pipeline
- The orientation of each defect on the pipe circumference
- Whether each defect is associated with other defects (for example corrosion within a dent), associated with pipeline features (such as seam or girth welds and their HAZ), or interacts with other defects through proximity
- The wall thickness, pipe material grade and diameter local to each defect
- Whether each defect is located on straight line pipe or on a fitting such as a bend
- Any supporting information associated with each defect (for example information which may indicate defect origin).

It should also be established if the inspections suffered from any issues such as velocity excursions or data corruption. The conclusions and recommendations of each inspection report and any follow-up reports such as fitness-for-purpose or corrosion growth studies should be reviewed. The relationship between different inspections over time should be established with respect to changes in the defect population and differences in the size and classification of defects. If defects were repaired following an inspection then the repaired defects, including coating repairs, should be identified in the inspection data, along with the following (which may be recorded on UKOPA FR/1 forms):

- Repair location
- Repair date
- Type of the repair
- Defect type, dimensions and orientation measured on-site (to validate inspection data).
- General coating condition at repair location (if available).

All of the above ground survey reports identified in Section 4.3.4 should be reviewed. The date and type of the survey (CP Test post, CIPS, DCVG etc.) should be established. Where relevant to the survey the following data should be confirmed:

- The overall performance of the CP system against established criteria (e.g. ECP/2)
- The location of areas of under-protection (instant off potentials above -850 mV)
- The location of areas of over-protection (instant off potentials below -1200 mV)
- The location of areas of AC or DC stray currents or interference from other nearby pipelines
- The number of coating defects reported
- The location of each coating defect
- The classification and size of each defect if applicable depending on survey type and vendor (e.g. %IR drop, P1, P2, P3 etc.)
- Whether each coating defect is associated with an area of under-protection or over-protection
- The type of coating local to each defect.

It should also be established if any areas along the pipeline route were not surveyed, for example due to land access issues, overgrowth, roads etc. The conclusions and recommendations of each survey report should be reviewed. The relationship between different surveys over time should be established with respect to changes in the coating and CP system. It should be determined if the results of surveys of different types can be correlated with each other, for example coating defects identified in CIPS correlated with coating defect locations in DCVG. It should also be determined if survey results can be correlated with the results of in-line inspection reports, e.g. areas of under protection from the CIPS correlated with identified corrosion growth of defects from in-line inspections. It should be noted that for pipelines located in close proximity crossover can occur affecting the results of CIPS and DCVG surveys. Issues affecting one pipeline may be reported as being associated with the other. Any documents relating to actions following a survey should be reviewed, for example excavations and repairs, soil resistivity tests, corrosion coupon studies, changes to maintenance etc. For repairs the same data as indicated above for repairs following in-line inspection should be established.

Any additional defect inspections performed for the pipeline should also be reviewed, for example external inspections in specific areas such as watercourses or girth weld excavation and inspection to the requirements of P/18. The date, location and type of inspection should be established along with the same data for each reported defect as stated above for the in-line inspection reports.

All of the above listed data, in addition to any other available supporting studies and reports relating to pipeline defects and defect management (for example, IGEM/TD/1 MOP affirmation reports, UKOPA Fault Database, CP anode replacement records etc.) should be used to develop an informed view of the condition of pipeline, its external coating and CP system and maintenance regime.

All of the defects identified from the inspections, or otherwise hypothesised to be present in the pipeline, which were not confirmed to be repaired should be assessed for hydrogen service at the proposed MOP using defect assessment methods appropriate to hydrogen service. Based on the results of small-scale tests conducted under laboratory conditions, the fracture toughness of the pipe steel is reduced, and the rate of fatigue crack growth is increased. A small number of full-scale burst and fatigue tests have been conducted on internal and external defects in lengths of line pipe containing gaseous hydrogen. There is some (limited) evidence that external defects are not significantly affected by the internal environment, but that internal defects are affected, see for example San Marchi et al., 2024 [22]. The evidence is not consistent, with some tests indicating an effect on the fatigue strength of external defects, and some tests indicating no effect on the burst strength of internal defects. In the absence of conclusive evidence, a conservative position should be adopted, i.e. the reduction in fracture toughness and the increase in the rate of fatigue crack growth should be considered when assessing internal and external defects.

It is recommended that GN/PM/P/11 Management Procedure for Inspection, Assessment and Repair of Damaged (Non-Leaking) Steel Pipelines above 150 mm Nominal Diameter and Designed to Operate at Pressures Greater than 2 bar[g] [23] be revised for application to hydrogen service.

Table 4.4 is a conservative assessment for hydrogen of the types of damage given in P/11 is given below, alongside the equivalent requirements for those damage types for natural gas:

Table 4.4 - Conservative Assessment for Types of Damage for Natural Gas and Hydrogen

Damage Type	Natural Gas	Hydrogen
Welding Arc Strikes	Acceptable	Acceptable
General Corrosion	Assess	Assess
Pitting Corrosion	Assess	Assess
Cracks or Spalling	Assess	Not acceptable
Smooth Dent	Assess	Assess
Smooth Dent plus General Corrosion	Assess	Assess
Smooth Dent plus Cracks or Spalling	Not acceptable	Not acceptable
Smooth Dent plus Gouge	Not acceptable	Not acceptable
Kinked Dent	Not acceptable	Not acceptable
Gouge	Assess	Not acceptable
Stress Corrosion Cracking	Not acceptable	Not acceptable

If any of the identified or hypothesised defects are found to be unfit for operation, they should be repaired using repair methods appropriate for hydrogen service. Any repairs made to the pipeline following previous inspections should also be assessed to determine if they are appropriate for hydrogen service. If any of the repairs are found to be unfit for operation, then they should be replaced using methods appropriate for hydrogen service. It is recommended that appropriate defect repair methods for hydrogen service are confirmed.

Any issues identified with the pipeline coating or CP system, such as severely degraded coating, CP under-protection or over protection, CP shielding, unacceptable stray AC or DC currents, lack of maintenance or other reasons for active corrosion growth should be rectified. It should be determined if any follow-up inspections, surveys or excavations are required. These may include for example a DCVG following a recent CIPS survey, additional CIPS surveys to cover areas missed due to access, excavation of defects identified during in-line inspections or above ground surveys. Outstanding recommendations made by inspection and above ground survey reports or their supporting reports should be followed. Any required changes to maintenance regimes should be identified and recommended, for example more frequent in-line inspections, CIPS surveys, surveillance to reduce encroachment and external interference etc.

If there is no information on defects currently located in the pipeline, then appropriate inspections and surveys should be performed to allow the pipeline condition to be assessed. Ideally an in-line inspection will be performed, however for pipelines which cannot be internally inspected a combination of above ground CIPS and DCVG surveys and demonstration of the integrity of the pipeline at the proposed operating pressure, for example via hydrotesting, may be satisfactory as a temporary measure. The inspection or above ground surveys should be followed up with verification digs of the identified defects.

4.4.5 Fatigue

In accordance with IGEM/TD/1 Edition 6, consideration must be given to the fatigue life of any pipeline to ensure that any defect which survives the hydrostatic test, or which is not detected by subsequent internal inspection, does not grow to a critical size under the influence of pressure cycling.

The rate of fatigue crack growth in steels in environments that contain hydrogen is higher than that in air. In accordance with IGEM/TD/1 Supplement 2, assessment of the fatigue life of a pipeline in hydrogen service must therefore consider the increased fatigue crack growth rate and the degradation of endurance limits. For pipelines which are being repurposed to hydrogen service, the assessment must also consider all defects and damage in the pipeline. IGEM/TD/1 Supplement 2 currently requires that all hoop stress cycles must be included in the fatigue assessment in hydrogen service, not just those greater than or equal to 35 Nmm^{-2}, however it is recommended that this requirement be revisited and appropriate research into fatigue crack growth in hydrogen at low stress cycle magnitudes is performed. Because fatigue crack growth is different in a hydrogen environment compared to natural gas, the assessment should consider the periods of natural gas operation and hydrogen operation separately. The endurance (S-N) curves and fatigue crack growth laws that are used in a fatigue assessment should be appropriate to the environment under consideration.

IGEM/TD/1 Edition 6 describes two approaches for defining the fatigue life of a pipeline: 1) the simplified approach, and 2) the detailed fracture mechanics approach. Supplement 2 describes the modifications to these two approaches for hydrogen service. A factor of 10 has been applied to the equation used in the simplified approach from IGEM/TD/1 Edition 6 to give the equation from Supplement 2. It is recommended that this factor is revisited, based on the semi-empirical derivation of the original equation, and the endurance and fatigue crack growth rate data from tests conducted in hydrogen. Guidance on approaches 1) and 2) is provided in Sections 4.4.5.1 and 4.4.5.2 below.

The full pressure cycle history of the pipeline under natural gas service from commissioning to present day including all periods of operation, as established in Section 4.3.5, should be applied as the cyclic loading for the natural gas part of the assessment. For this purpose, the pressure cycles for natural gas operation should be converted into stress cycles using the formula:

$$\Delta\sigma = \frac{\Delta PD}{20t}$$

Equation 4.3

Where ΔP is the pressure cycle size in bar and Δσ is the stress cycle size in Nmm^{-2}, D is the pipeline outside diameter in mm and t is the nominal wall thickness in mm. The conversion of all pressure cycles should be performed for all distinct pipeline sections (different nominal wall thicknesses, diameters etc.) so that a stress cycle profile applicable to each is derived.

If the pressure cycle history of the pipeline under natural gas, or portions of the history, are available as raw pressure/time data then a rain flow count of the pressure cycles should be performed of the data before the cycles are converted to stress cycles. Summary spreadsheets or sources including annual or cumulative counts of cycles may already present the cycles as stress. The stress cycles may also be presented as a number of cycles equivalent to 125 Nmm^{-2}.

As previously noted there may be gaps in the available records relating to the pressure cycle history for the pipeline. In these cases, assumptions should be made for the purposes of the assessment regarding the pressure/stress cycling experienced by the pipeline during the periods for which data is missing. Any assumptions should be conservative and consider the available pressure cycle history, the operating conditions of the pipeline during that period and any other supporting information. A complete stress cycle history for the pipeline for the period of natural gas operation should be established using available data and assumed data.

For the period of hydrogen operation, the future projected annual pressure/stress cycling in the pipeline should be established to be applied as the cyclic loading for the hydrogen part of the assessment.
IGEM/TD/1 Simplified Approach

In the IGEM/TD/1 simplified approach, the fatigue curve taken from IGEM/TD/1 Edition 6 should be applied for the natural gas part of the calculation:

$$S^3N = 2.93 \text{ x } 10^{10}$$

Equation 4.4

Where S is the stress range in Nmm^{-2} and N is the allowable number of cycles of that range. S in Equation 4.4 should be the stress range for any given pressure cycle calculated using Equation 4.3. Equation 4.4 should be used to calculate values of S and N for all pressure cycles experienced by the pipeline during natural gas operation and these should be summed using Miner's rule to calculate the damage fraction:

$$D_F = \sum \frac{n_i}{N_i}$$

Equation 4.5

Where D_F is the damage fraction n_i is the number of cycles of stress S_i experienced by the dent and N_i is the maximum allowable number of cycles of stress S_i for the dent. Note that for natural gas operation there is an endurance limit of 35 Nmm^{-2} and therefore cycles with a stress range below this value should not be counted using Miner's rule.

For the hydrogen part of the calculation the equivalent fatigue curve for hydrogen operation taken from IGEM/TD/1 Supplement 2 should be used:

$$S^3N = 2.93 \text{ x } 10^9$$

Equation 4.6

Equation 4.6 should be used to calculate values of S and N for all pressure cycles experienced by the pipeline annually during hydrogen operation and these should be summed using Miner's rule to give the annual damage fraction in hydrogen operation. Note that for hydrogen operation, pending the outcomes of further research, an endurance limit does not apply and therefore cycles with a stress range below 35 Nmm^{-2} should be counted using Miner's rule.

The damage fraction in hydrogen operation added to the damage fraction for natural gas operation gives the overall damage fraction. The number of annual damage fractions in hydrogen operation which can be added to the damage fraction for natural gas operation before the value of the overall damage fraction reaches 1 represents the fatigue life of the pipeline in hydrogen operation.

Note that an endurance approach, similar to the simplified approach but using specific S-N curves, may also be applied. For natural gas, the standard design curves from BS 7608:2014 [24] may be applied. The recommended endurance curves for steels in hydrogen service are based on the BS 7608 curves, with a modification proposed by Haldorsen et al., 2024 [25]. Note that Clause S7.11.2 of IGEM/TD/13 Supplement 1 states that a reduction factor of 50 on the predicted life calculated using the S-N curves applied in IGEM/TD/12. This approach is more conservative than the BS 7608 curves modified by Haldorsen.

4.4.5.2 Detailed Fracture Mechanics Approach

A fatigue assessment using the detailed fracture mechanics approach should be conducted in accordance with BS 7910.

It is recommended that */SP/TR/19 Specification for Assessing the Fatigue Life of Transmission Pipelines Designed in Accordance with IGEM/TD/1, which provides guidance on performing a fracture mechanics fatigue assessment, is revised and rewritten for application to hydrogen service.

The recommended fatigue crack growth laws for steels in hydrogen service are: ASME B31.12 Code Case 220 [26], and Table S2 and Figure S4b in IGEM/TD/1 Supplement 2 – Table S2 is more conservative than Code Case 220, but it is simpler to implement (because of its treatment of residual stresses). Code Case 220 is an (approximate) mean, not an upper bound crack growth law. The implications of this should be addressed in an assessment.

4.4.6 Fatigue Life of Defects

The fatigue life of all defects identified in the pipeline in Section 4.3.4 should also be considered. As above, the assessments should consider the periods of natural gas operation and hydrogen operation separately.

For defects it should be determined when the defect was introduced into the pipeline and only the cyclic stress loading corresponding to the period of operation after this point should be applied as part of the natural gas calculation. Additionally, the initial defect depth and length for the natural gas part of the assessment should be the measured values of the defect from inspection or direct measurement (if verified in-field).

For crack-like defects, including gouges which may be assumed to be crack-like, a detailed fracture mechanics approach for fatigue life calculation may be applied. It is recommended that methods for the fatigue assessment of defects other than crack-like defects in a hydrogen environment are developed.

If the fatigue life of any defect located in the pipeline is calculated to be unsuitable for operational requirements, then it is recommended that the defect is repaired using methods which are appropriate for hydrogen service.

4.4.7 External Loads

In accordance with IGEM/TD/1 Edition 6, a pipeline must be able to withstand additional loading from:

- The weight of the pipeline
- Soil dead weight due to depth of cover
- Impact protection slabs
- Pipe laying and alignment; for example tie-in connections
- Differential settlement due to variable support arising from trench bottom and bedding conditions
- Pressure testing
- Subsidence or settlement due to mining and mineral extraction, de-watering, or the action of additional surface loads, typically embankments
- Subsidence due to the pipe being laid on top of disturbed or built-up land, taking into account the effects of differences in support between existing pipe and modified pipe at a tie-in interface
- Slope instability
- Frost heave
- Buoyancy
- Live loading from vehicles
- Seismic activity

For in-service pipelines, the effects of any additional load must be determined and assessed for acceptability. The analysis should use pressure and temperature values relevant to the location of the additional load and take into account any uncertainties in the load or displacement.

In accordance with IGEM/TD/1 Supplement 2, the maximum through-wall circumferential hoop stress for a pipeline in hydrogen service, resulting from all operational and additional loads, should meet the design factor requirements as described in Section 4.4.1. Additionally, the maximum tensile longitudinal stress for a pipeline in hydrogen service, , resulting from all operational and additional loads, should be less than or equal to 180 Nmm^{-2}. The purpose of this limit is to maintain consistency with the limit on hoop stress. For assessment of ovalisation of the pipeline under additional loading, the radial deflection must not exceed 5 % of the nominal pipe diameter.

Any documents identified during the pipeline records review in Section 4.1 relating to external pipeline loading should be reviewed. It should be established using these documents whether the external loading experienced by the pipeline complies with the requirements of IGEM/TD/1 Edition 6 and IGEM/TD/1 Supplement 2. Relevant documents may include:

- Pre-construction mining or seismic surveys of the pipeline route
- Line-walks indicating ground movement or external loading
- British Geological Survey data for the pipeline location
- Watercourse crossing surveys
- IGEM/TD/1 MOP Affirmation reports.

Any external loads affecting the pipeline which are found to not be compliant with IGEM/TD/1 Edition 6 and IGEM/TD/1 Supplement 2 should be remediated if possible. If remediation is not possible then a fitness-for-purpose assessment should be completed to assess the risk posed by the pipeline and the consequences of failure in hydrogen service to support safe repurposing.

If there is no information regarding external loading to the pipeline, then a line-walk survey of the full pipeline route or inspection using an in-line inspection tool equipped with an inertial measurement unit capable of measuring curvature and bend strain/shape profiles should be performed to improve understanding of potential external loading or ground movement and determine if further action is required.

4.4.8 Depth of Cover

In accordance with IGEM/TD/1 Edition 6 the minimum depths of cover for different locations on an operating pipeline are shown in Table 4.5. The depth of cover is measured from the lowest ground surface level to the top of the pipeline, including the coatings and attachments.

Table 4.5 - Minimum Depth of Cover

Location	Minimum Depth of Cover (m)
Rural	1.1
Suburban	1.1
Roads	1.2
Watercourses, canals, rivers	1.2
Railways	1.4

Any documents identified during the pipeline records review in Section 4.1 relating to the pipeline depth of cover should be reviewed. It should be established using these documents whether the depth of cover along the pipeline route complies with the requirements of IGEM/TD/1. Relevant documents may include:

- Design and construction documents including daily construction logs, as-built drawings, crossing drawings
- Depth of cover line-walk surveys
- Watercourse crossing surveys.

There may be areas where the depth of cover of the pipeline complies with IGEM/TD/1 Edition 6 and other areas where it does not. Areas where the depth of cover is found to not be compliant with IGEM/TD/1 Edition 6 should be remediated if possible. If remediation is not possible then a fitness-for-purpose assessment should be completed to assess the risk posed by the pipeline and the consequences of failure in hydrogen service to support safe repurposing. It is acknowledged that IGE/TD/1 Edition 1 contained a depth of cover requirement of 0.9 m, therefore pipelines designed, operated and maintained to this edition are unlikely to ever meet the requirements of Edition 6.

If there is no information relating to depth of cover for the pipeline or the available information is several years old, then a depth of cover line-walk survey of the full pipeline route should be performed to improve understanding and determine if further action is required.

4.4.9 Temperature

From IGEM/TD/1 Edition 6, the normal operating temperature of a buried gas transmission system will vary according to the seasonal changes in the ground temperature and the distance from PRIs. The ground temperature in Great Britain will generally be in excess of 5°C. The minimum design temperature for a pipeline should be 0°C.

As noted in Section 4.4.2, it is required that all pipe material has sufficient energy absorption to ensure resistance to fracture initiation and propagation at the minimum design temperature. Additionally, the material properties of line pipe, fittings, coating and lining should be adequate for the conditions that arise both at the minimum and maximum design temperatures, including the effects of contraction and expansion due to climatic temperature variation, as well as the normal design condition.

Any temperature data relating to pipeline operation identified during the pipeline records review in Section 4.1 should be reviewed. It should be established using this data whether the temperatures experienced by the pipeline are appropriate for hydrogen operation for the pipe materials identified in Sections 4.3.1 and 4.3.2 and assessed in Sections 4.4.2 and 4.4.3. Proximity to PRIs should be considered as part of the assessment and the temperature along the full pipeline route should be assessed. Relevant data may include:

- Raw temperature/time data recorded by transducers at installations
- Local ground temperature data measured in weather or geological surveys.

If the pipeline temperature at any point along the pipeline route is found to not be appropriate for the pipe materials during hydrogen operation, then remedial measures are required. If remediation is not possible then a fitness-for-purpose assessment including material qualification should be completed to assess the acceptability for hydrogen service.

4.5 Pipeline Risk Assessment

Individual and societal risk levels for repurposed pipelines in hydrogen service will be greater than in natural gas service for the following reasons:

- Effect of hydrogen embrittlement on fracture toughness, elongation and fatigue crack growth [27]
- Overpressure hazard distances being greater than for thermal radiation, unlike natural gas
- Ignition probability being higher than for natural gas.

Natural gas pipelines designed, constructed, operated and maintained in accordance with IGEM/TD/1 and gas industry standards, policies and procedures have implicitly acceptable levels of risk. Infringements to IGEM/TD/1, for building proximity, population density or traffic crossings, are justified using Quantified Risk Assessment (QRA) carried out by competent risk assessment practitioners in accordance with IGEM/TD/2 [28]. However, due to the probable increase in failure frequency and consequences during hydrogen service, previously assessed locations may no longer be broadly acceptable or as low as reasonably practicable (ALARP).

Therefore, QRA should be carried out for any pipeline proposed for repurposing to hydrogen service to confirm that risk levels remain broadly acceptable or ALARP.

4.5.1 Identification of Locations for QRA

Currently, the recommended building proximity distances (BPDs) for hydrogen pipelines are the same as for natural gas [29] so there are no additional infringements to IGEM/TD/1. However, the BPDs do not take into account the increased frequency of an ignited hydrogen release or the additional overpressure hazard. IGEM are in the process of updating the TD/1 and TD/13 hydrogen supplements and the inclusion of overpressure in the calculation of BPDs for pipelines carrying hydrogen is under consideration.

Prior to any repurposing for hydrogen service, all proximity, population density and traffic crossing infringements to IGEM/TD/1, using the appropriate BPD, shall be identified as part of an MOP Affirmation study. The infringement location with the highest expected risk, typically the population density infringement with the greatest population within the maximum hazard distance, should be subject to QRA. If the risk levels for this location are shown to be broadly acceptable or ALARP, then all the other infringements, with lower estimated risk levels will also be ALARP.

If there are no infringements to IGEM/TD/1, then the most highly populated location along the pipeline should be assessed, in accordance with the general principles of IGEM/TD/2, to confirm that risk levels remain broadly acceptable or ALARP. The effect of overpressure on populations adjacent to the pipeline should be considered.

4.5.2 Effect of Hydrogen Embrittlement

Hydrogen embrittlement is the degradation of mechanical properties caused by the exposure of a material to a hydrogen-containing environment. This can lead to failures at applied loads below a material's yield strength and can cause usually ductile metals to fail in a brittle manner. The severity and mechanisms of hydrogen embrittlement is dependent on a combination of the following 3 factors:

- Mechanical Loading – especially cyclic loading which can cause hydrogen accelerated fatigue
- Susceptible Material – depending on the composition and microstructure
- Hydrogen Environment – specifically the partial pressure of hydrogen[5].

The effect of hydrogen embrittlement on pipeline steel properties, in terms of reduced fracture toughness, reduced tensile elongation and increased fatigue crack growth, is an active area of research with ongoing full and small-scale test programs. Based on the literature review of previous studies summarised in [30], observations on the susceptibility of repurposed pipelines to typical threats to pipeline integrity can be made.

The effect on the failure pressure of blunt defects, e.g. corrosion, is expected to be limited, because the yield strength is not significantly reduced in hydrogen, and standard assessment methods, e.g. [31] can still be used. Hydrogen will increase fatigue crack growth rates (FCGRs) and decrease fracture toughness. Sharp defects or defects where fatigue cracks can be initiated will be of concern in hydrogen service. HIC, SCC and spontaneous cracking at hard spots, which are threats in wet sour gas service pipelines, are unlikely in operational hydrogen pipelines due to the lower levels of atomic hydrogen, produced as part of HIC or SCC corrosion processes in the pipeline steel.

The reduction in cycles to crack initiation means that fatigue cracks are likely to initiate at areas of stress concentration or plastic strain, e.g. weld toes, dents and areas of ground movement. Small-scale testing for LTS Futures has shown no significant reduction in the fatigue life of parent material in hydrogen service. Fatigue cycling will need to be actively managed, bearing in mind that higher flow rates that may be required in hydrogen service, will lead to increased pressure cycling. There is some evidence that internal sharp-edged features, e.g. cracks, will have a reduced critical crack size and hence a lower failure pressure in hydrogen service [32].

The effect of hydrogen service on typical pipeline integrity threats and their susceptibility, compared to natural gas service, is shown in Table 2.1.

4.5.3 Failure Frequency Assessment

As Table 4.6 summarises, the susceptibility of repurposed pipelines carrying hydrogen to external interference, fatigue, including of manufacturing and construction defects, and ground movement is expected to increase. Until the results of ongoing full- and small-scale tests are known, it is recommended that the following conservative approach to failure frequency for use in pipeline QRA is followed.

Table 4.6 - Recommended Approach to Failure Frequencies for Pipeline QRA

Threat	Comment
External Corrosion	Use IGEM/TD/2 recommended historic values.
External Interference	Increase predicted failure frequencies by a factor of 5. UKOPA recommendations on predictive modelling [33] should be followed.
Ground Movement	Use IGEM/TD/2 ground movement model assuming 'poor quality' girth welds
Material and Construction Defects	Increase IGEM/TD/2 recommended historic frequencies by a factor of 5.

4.5.4 Consequence Assessment

The assessment of the consequences of a release of hydrogen should follow the guidance in IGEM/TD/2 as per natural gas with differences in the following key areas:

- Ignition Probability
- Split between immediate and delayed ignition
- Inclusion of overpressure effects.

It should also be noted that thermal radiation levels from hydrogen pipeline fires will be approximately 90 % of the equivalent natural gas fire [30].

Limited full-scale tests of hydrogen vent, leak and rupture releases have been carried out to date and further full-scale rupture tests to assist in defining suitable assumptions in the above areas are planned in 2026.

The assumptions outlined below are considered to be current best practice and have been used by the LTS Futures project for the QRAs of the Grangemouth to Granton and 3" Hydrogen Supply pipelines.

[5] Note that the Blueprint applies exclusively to pipelines transporting 100 % hydrogen, therefore the partial pressure of hydrogen is the operating pressure of the pipeline.

4.5.4.1 Ignition Probability

Hydrogen has a much wider flammability range (approximately 4 – 75 %) and a significantly lower minimum ignition energy (MIE) (0.01 mJ compared to 0.26 mJ) than natural gas so the ignition probability of a hydrogen pipeline rupture is expected to be higher than for an equivalent natural gas release. There is limited worldwide operational data to determine appropriate values and a cautious, probably conservative, approach based on Norwegian guidance has been currently adopted [34].

Therefore, until additional data is available, the ignition probability for hydrogen pipeline ruptures should be taken to be 1.0.

For hydrogen puncture releases, the HYEX model for the probability of ignition (P_{ign}) is currently recommended:

$$P_{ign} = \min(1.0; 0.55 \text{ x Leak Rate}^{0.87;} 0.267 \text{ x Leak Rate}^{0.52})$$

Equation 4.7

4.5.4.2 Immediate and Delayed Ignition

The split between immediate (or almost immediate) and delayed ignition is also subject to uncertainty due to the lack of operational failures of hydrogen pipelines. It is currently recommended that the split between immediate and delayed ignition should be 2/3: 1/3.

Due to the wider flammability range and lower MIE, it is considered that the delayed ignition of a hydrogen release will occur earlier than an equivalent natural gas release (typically assumed to be 30 seconds in natural gas pipeline QRA methodology).

4.5.4.3 Overpressure

Following the transient FutureGrid full-scale test, it is currently assumed that both immediate and delayed ignition events have the potential to generate significant levels of overpressure. It's considered to be good practice to conservatively assume ignition occurs when overpressure will be at a maximum. For the overpressure calculations in the LTS Futures QRAs, the immediate ignition cases are therefore assumed to have a very short 100 ms ignition delay and are generally referred to as immediate (early) ignition. For the delayed ignition cases, overpressure should be calculated for the time when the hydrogen plume is at its largest extent (typically between 5 and 15 seconds).

The vulnerability of people indoors and outdoors to overpressure depends on the strength and duration of the overpressure wave as well as the type and design of building. Chemical Industries Association (CIA) guidance [35] states that overpressures below 30 mbar are insufficient to cause structural damage or significant window glass hazards.

The CIA guidance also provides vulnerability curves for a range of buildings designed to be used for screening existing site occupied buildings. This gives a 1 % chance of fatality for an overpressure of 50 mbar and 50 % chance of fatality for an overpressure of approximately 300 mbar to occupants of typical office and domestic buildings in the UK.

The CIA guidance is conservative compared to values used by HSE in setting land use planning (LUP) zones around sites overpressure [36, 37], see Table 4.7.

Table 4.7 - HSE LUP Zones for Overpressure

HSE LUP Zone	Peak Overpressure (mbar)	Comment
Inner	600	50 % fatality in normal population indoors
Middle	140	Dangerous dose in normal population indoors (1 % fatality)
Outer	70	Dangerous dose in vulnerable populations indoors (1 % fatality)

Beyond the Outer Zone, the so-called Consultation Distance where peak overpressures are less than 70 mbar, fatalities are unlikely [36] .

For the LTS Futures projects DNV used the following conservative assumptions, based on the CIA guidance, for the Grangemouth to Granton and 3" Hydrogen Supply Pipeline QRAs, see Table 4.8.

Table 4.8 - DNV Overpressure Vulnerability Assumptions

Peak Overpressure (mbar)	Comment
40	Fatality of most vulnerable 1 % indoors. Breaking of typical windows
70	HSE Outer Zone Boundary
200	Fatality of the most vulnerable 1 % when outdoors.
300	Fatality of around 50 % of building occupants. Fatality of around 50 % outdoors.

Care must be taken when combining overpressure and thermal radiation results to avoid double counting fatalities and any assumptions used regarding the independence of effects on specific population groups and/or the use of upper or lower bound estimates must be clearly stated.

4.5.5 Individual and Societal Risk Assessment

Calculated individual risks should be assessed against HSE individual risk criteria [38, 39]. Please note that it is very common for UK gas transmission pipelines to have individual risk levels above the HSE broadly acceptable level and industry experience shows that societal risk is a better measure to assist with making decisions around high pressure pipelines.

Calculated societal risk FN curves should be assessed against the societal risk criteria in IGEM/TD/1 and IGEM/TD/2. This criterion was developed by assessing 30 years of safe and successful operation of high-pressure natural gas pipelines and can be considered to represent the risk level of the existing natural gas network.

4.5.6 ALARP Assessment

If the calculated societal risk for a location on a repurposed hydrogen pipeline is greater than the IGEM/TD/1 and TD/2 broadly acceptable level, then an ALARP assessment in accordance with UKOPA good practice [40] and HSE guidance [39] is required.

Please note that HSE take account of the use of physical risk mitigation measures, such as concrete slabbing, rather than procedural measures, such as increased surveillance, for long term risk reduction.

4.6 Pipeline Safety Justification

The pipeline safety justification shall bring together the outputs of the design and operability data assessment, detailed technical assessments and pipeline risk assessment to demonstrate that the pipeline is suitable for operation in hydrogen service.

The safety justification shall document the basis on which the pipeline is considered fit for hydrogen service, including identified risks, applied mitigation measures, operational constraints, and any assumptions requiring validation.

The safety justification shall confirm that risks associated with hydrogen service are ALARP and that any conditions for repurposing are clearly defined prior to change of service.

4.6.1 Asset Details

Confirmation that all asset records have been updated to reflect hydrogen service, including any changes arising from the repurposing works, including:

- Asset registers, drawings and associated records.
- Confirmation that marker posts and warning signs are appropriate for hydrogen service and have been installed in accordance with applicable requirements.

4.6.2 Modifications

Confirmation that all documentation associated with modifications required for hydrogen repurposing is complete including:

- Modification details
- Confirmation of design, installation, testing, completion and approval in accordance with IGEM/GL/5 [41] or equivalent
- All records and drawings have been updated to reflect the as-modified pipeline.

4.6.3 Risk Mitigation

Document that any risk mitigation measures implemented to ensure risks associated with hydrogen service are reduced to ALARP, including:

- Details of risk mitigation measures required
- Confirmation of installation, completion and approval
- Residual risk identification and the acceptance basis.

4.6.4 Revalidation

Address revalidation requirements arising from repurposing, including:

- Assessment of any changes to safety factors or operating conditions
- Confirmation that revalidation activities have been completed, checked and approved where required
- Identification and validation of assumptions relied upon in the assessment.

4.7 Pipeline Repurposing Decision Report

The Pipeline Hydrogen Repurposing Report shall record the final decision on whether the pipeline is suitable to be repurposed for hydrogen service. The report shall:

- Confirm the defined scope of the pipeline and the intended hydrogen operating conditions.
- Confirm that the pipeline safety justification has been completed and approved.
- Confirm that all technical requirements for repurposing have been satisfied, or that any outstanding issues are subject to defined conditions or constraints.
- Record the final decision to accept the pipeline for hydrogen service, accept it subject to specified conditions, or reject it pending further work.
- Record the authority and basis for the decision.

5. Methodology for Repurposing LTS Installations

Repurposing of LTS installations shall follow a structured, evidence-based process consistent with IGEM/TD/13 Edition 3 Supplement 1.

The repurposing methodology commences once capacity assessments in Section 3.2 are completed. Repurposing shall not proceed unless all relevant connecting pipelines are confirmed suitable for hydrogen service in accordance with Section 4, or an approved alternative supply arrangement is in place.

The Methodology for Repurposing LTS Installations is outlined below:

1. **Viability assessment** – identification of any fundamental characteristic that would preclude repurposing, including flow analysis and assessment of pressure drop across installation.
    - Upstream and downstream connection – confirm that connecting systems are suitable for the intended hydrogen operating conditions, noting that pipeline modifications typically represent the primary cost driver.
    - Installation capacity – confirm that the installation can meet the required hydrogen operation conditions.
    - Equipment and configuration constraints - identify limitations such as inadequate isolation (i.e. double block and bleed isolation not available), poor condition, or hazardous area implications that would require disproportionate modification or redesign of the installation.
    - Known issues in current natural gas service - identify existing issues including flooding, vibration, or noise that could affect hydrogen operation.
2. **Design and condition assessment** – design review including materials acceptability, stress and fatigue analysis, review of operation and maintenance data to identify recorded defects and damage and identification of all modifications necessary for future operation.
3. **Integrity status** – confirmation of inspection and damage assessment studies identified in (2) to confirm that the condition, integrity and functionality of the installation following the change of service are acceptable.
4. **Functionality and operability studies** - confirm that control, protection, detection, and operational interaction remain effective and practicable under hydrogen service across all intended operating conditions.
5. **Modification** – completion of all necessary modifications identified in (2), (3), and (4) to ensure functionality and operability for future hydrogen service.
6. **Validation** – formal confirmation that the condition, integrity, functionality, operability and safety of the installation and the risks posed by it are acceptable for the proposed repurposing.
7. **Change of service** – regulatory notification shall be submitted to the regulator. This will be captured under the Pipelines Safety Regulations notifications.
8. **Change of service** – commissioning – introduction of hydrogen and controlled increase of pressure to the new MOP.

The assessment is structured as a series of defined stages, summarised in Table 5.1. Progression beyond each stage shall depend on confirmation that repurposing remains justified when compared with a new-build option. The objectives and outputs may be combined into one or more reports.

Table 5.1 -Outline of Stages in the Methodology for Repurposing LTS Installations

Section	Objective	Output
5.1 Viability Assessment	High level assessment of suitability for repurposing and compliance with IGEM/TD/13	Record Register and Audit Checklist
5.2 Design and Condition Assessment	Assess materials for use with hydrogen, mechanical and functional suitability.	Assessment Report
5.3 Integrity Status	Confirm condition of pressure containing, structural and safety systems.	Integrity Summary
5.4 Functionality and Operability Studies	Evaluate performance under hydrogen conditions and define required modifications.	Operability Recommendations
5.5 Installation Risk Assessment	Evaluate hydrogen specific hazards, failure modes, and consequences to demonstrate that risks from operation in hydrogen service are ALARP and compliant with DSEAR, IGEM/TD/13 and the applicable hydrogen supplement.	Risk Evaluation
5.6 Installation Safety Justification	Demonstrate that the installation can be safely operated in hydrogen service and that all required modifications, mitigations and assurance activities have been completed.	Installation Safety Justification confirming compliance with IGEM/GL/5 or equivalent.
5.7 Installation Hydrogen Repurposing Decision Report	Compile all assessment and validation outputs to provide a single, authoritative statement of the suitability for hydrogen service of the installation.	Installation Hydrogen Suitability Decision Report

5.1 Viability Assessment

The viability assessment shall identify any fundamental characteristics that would preclude repurposing before detailed assessment is undertaken.

The scope shall include the physical limits of the installation, all pressure-containing and safety-related equipment within those limits, and the intended operating conditions for hydrogen service.

The defined scope shall state the assessment boundaries, interfaces with connecting systems, and any exclusions, together with the basis for those exclusions. Where installations will include both natural gas and hydrogen systems, the scope shall define the separation arrangements and any interface points between the two systems. All subsequent assessments shall be undertaken within this defined scope.

5.1.1 Installation Records Review

Table 5.2 identifies the records required to support the assessment of an installation for repurposing to hydrogen service. The adequacy and completeness of each record should be reviewed to determine whether additional inspection, sampling, or testing is required. Efforts shall be made to locate, recover, and compile all records required for the assessment, including searches for physical paper documentation.

Where construction records are incomplete or unavailable, reasonable assumptions may be made regarding pipework material grade, wall thickness and seam type based on the known construction era and applicable historical standards (e.g. BGC/PS/DAT/6). Such assumptions shall be clearly justified and documented.

Where pipework connections are made to existing pipelines, the connected pipeline data may be used to inform assumptions for the installation pipework, recognising that installation pipework may have differing specifications and seam types which are not directly evidenced in records.

Assumptions shall be validated, where practicable, through inspection and measurement (e.g. outside diameter, wall thickness where accessible). Any judgement should be independently validated.

Table 5.2 -Baseline Records for Installation Repurposing Assessment

Record Type/ Requirement	Purpose/Comment
Construction Year	Establishes design period and applicable standards, informs likelihood of manufactured gas service. Where no explicit record is available, the construction year may be inferred from the connecting pipeline(s), provided there are no records to the contrary. Additional potential evidence sources for determining the construction year include asset assembly name plates and hot tap records which may be associated with the connect pipelines.
Design Standard	Identifies the design and associated requirements applied at the time of construction. The applicable standard will depend on the year of construction and may include current or legacy editions of IGEM/TD/13 or its predecessor IGE/TD/9. For certain installations, reference to current or legacy editions of IGEM/TD/1 will be necessary where that standard governed specific installation design including block valves and pig traps. Applicable standards include IGEM/TD/13 Edition 3 [5], IGEM/TD/13 Edition 2 [42], IGE/TD/13 [43], IGE/TD/9:1975 [44] and IGE/TD/9:1986 [45]. Note that IGEM/TD/1 Edition 5 and earlier covered block valves and pig traps.
MOP/SOL	Defines the current maximum operating pressure and other safe operating limits.
Pressure System Diagram	Provides installation configuration, flow direction, and pressure boundaries.
Drawings	Confirms actual layout and aids verification against design intent. Includes site layout, general arrangements, piping and instrument drawings.
Operating Pressure History	Demonstrates current pressure containment capacity and historical pressure performance.
Flowrate	Demonstrates current and historical flowrates, compliance with gas velocity design limits, and supports erosion, noise and vibration assessments.
Manufactured Gas Service	Identifies potential legacy exposure and potential risk of internal stress corrosion cracking. See Section 4.3.6 for further guidance. Installations assessed as potentially at risk from ISCC due to manufactured gas service are generally more accessible for inspection than buried pipelines.
Modifications	Demonstrates compliance with relevant standards and traceability through a formal change control process (e.g., IGEM/GL/5 or equivalent). Supporting evidence should include design reports, construction and commissioning records, and test results. The documentation may be held at a project level rather than a specific installation data repository.

Record Type/ Requirement	Purpose/Comment
Inspection History	Evidence of compliance with Written Scheme of Examination (WSoE), and records of defect management.
Maintenance History	Demonstrates that maintenance has been completed in accordance with relevant maintenance procedures and records of fault management.
Pipework Design	Confirms pipe materials, diameter, wall thickness, grade, and seam type to support hydrogen suitability. Records should include material certification and, where available, fabrication and welding details. Above-ground sections can be verified by material sampling, dimension and wall-thickness measurement, and visual inspection. Buried sections may require targeted excavation for sampling.
Asset Records	Material and component data (manufacturer, model, materials, pressure rating). Records should include equipment data sheets, manufacturer specifications, and any associated test or inspection certificates. Pressure vessels and valves should include details recorded on the data plate.
Hydrostatic Test Records	Confirms initial and any modification pressure tests. Data plates should record manufacturer's test pressure and date. The pressure history can be used to demonstrate pressure containment to a known level.
Stress Analysis and Fatigue	Demonstrates adequacy of design stress margins and fatigue life. Qualitative justification if formal analysis absent.
Vibration and Noise	Confirms compliance with operational limits and mitigation of issues. Interviews with operational personnel and/or site surveys where appropriate may be required.
Auxiliary Pipework, Fittings, Gaskets and Bolts	Confirms compatibility of materials and sealing components for hydrogen. Site surveys may be required. Where material verification is not practicable, full replacement may be assessed as the most effective option.
Hazardous Area Assessment	Evaluates the impact on the surrounding environment and demonstrates that the installation operates within the required hazardous area. A hydrogen specific assessment requires confirmation of the suitability of existing vents and breathers. The assessment should include hazardous area drawings and calculations.
Metering	Confirms current metering type.
Cathodic Protection Records	Demonstrates that all buried pipework has a cathodic protection system installed, the system is compliant with maintenance procedures, and that any required remedial works have been completed.
Site Condition Surveys	Confirms visible equipment condition and identifies remedial actions.
Electrical and Instrumentation Equipment	Confirms compliance with ATEX Group IIC for hydrogen. Requires site verification survey where uncertain.

In addition to the records identified in Table 5.2, other documentation may be available that supports the repurposing assessment. These include engineering analyses, integrity evaluations, validation reports, or other technical evidence developed to demonstrate safe operation or confirm material and component performance. Where available, these records should be reviewed and referenced within the repurposing assessment.

5.1.2 PRI Details and Limits for Repurposing

A site survey shall be performed to verify the accuracy of records and to generate new records where information is unsuitable to inform the repurposing process due to being incomplete or unavailable. See Section 5.1.4.

The following details shall be confirmed or established reflecting the current installation configuration and operational service. This list is not exhaustive and additional installation specific considerations may apply:

- Site layout drawings, General Arrangement (GA) drawings, Piping and Instrumentation Drawings (P&IDs), Engineering Line Drawing (ELDs)
- Upstream and downstream design pressure
- Gas velocities
- Capacity
- Fittings and class ratings
- Associated systems including civils, buildings, kiosks, ventilation, control systems, electrical and instrumentation equipment, and software
- Hazardous area assessment, hazardous area drawings, and calculations
- Nearby infrastructure, Occupied Buildings Assessment.

The following details shall be confirmed reflecting the current and appropriate representative historical operation of the installation:

- Maximum and minimum inlet and outlet operating pressures
- Maximum and minimum flow rates
- Maximum and minimum operating temperatures
- In-service inspection and maintenance records
- Damage, vibration, noise
- Corrosion protection data
- Modification and repair records.

Where flanged fittings are installed, a site survey should document the flange configuration. Features that are accessible and can be readily measured including outside diameter and thickness of flange, diameter of bolt circle, number and nominal diameter of bolts can be matched to the dimensional requirements in relevant standards e.g. BS 1560 [46] (for flanges up to and including 250 mm nominal size), MSS SP-44 [47] (for flanges equal to or greater than 300 mm nominal size), and ASME B16.5 [48] to determine the original pressure class. Once identified, the class rating provides a screening limit for allowable pressure. At ambient temperature, typical values are approximately:

- 19 bar for Class 150
- 49 bar for Class 300
- 100 bar for Class 600.

Where the proposed hydrogen design pressure lies within the corresponding class rating, the fitting will generally be sufficient to demonstrate adequacy, subject to confirmation that all components of the joint are consistent with that class. Where the class cannot be confidently established, mixed-class assemblies are present, or the proposed pressure exceeds the indicative class limits, a fitness-for-purpose assessment shall be performed to demonstrate suitability for hydrogen service.

The minimum pipe grade may be bracketed using the known flange class and nominal size. Technical */SP/F/1 [49] contains material tables which provide the minimum flange grades associated with each class, nominal size, and wall thickness. As flanges are not weaker than the connected pipe, these values may be used to infer a conservative lower bound for the pipe SMYS. This approach is suitable for screening but shall be validated through material verification or testing where required for hydrogen service. It is noted that */SP/F/1 includes grades above X52 for certain combinations of nominal size, wall thickness and flange class. This shall be taken into account when using flange data to infer a conservative lower bound for pipe SMYS.

Analysis of the LTS pipeline network shows that grade X56 line pipe, the standard grade above X52, was first used for pipelines commissioned in 1967. In the absence of adequate records, wall thickness shall be measured to determine an appropriate nominal value for use in design and condition assessments.

5.1.3 Initial Fitness for Purpose Assessment

The initial fitness for purpose assessment provides a preliminary evaluation of whether the existing installation and its components are likely to be suitable for repurposing to hydrogen service. It is used to identify any immediate constraints, data gaps, or areas requiring further detailed assessment.

The following aspects shall be reviewed:

- Capacity assessment to confirm pipework and equipment can support required flowrates
- Impact of hydrogen on hazardous area and nearby infrastructure
- Acceptability of existing class rating
- Impact of minimum fracture toughness and maximum crack growth rate on future hydrogen service
- Historical damage assessment under proposed hydrogen service
- Confirmation of viability for repurposing.

The assessment shall consider equipment obsolescence and long-term maintainability, including availability of Original Equipment Manufacturer (OEM) support, critical spare parts, and hydrogen-rated variants. Obsolescence may represent a practical constraint to repurposing, even where technical compatibility can be demonstrated.

5.1.4 Sampling of Components, Materials, Fittings for Hydrogen Service

Where records are incomplete or uncertain, the associated risk shall be reduced through targeted sampling, inspection and testing to confirm material and component suitability for hydrogen service.

Sampling and testing should be conducted in accordance with */Q/10 [50]. A database of material testing results should be developed and maintained to support subsequent repurposing studies (see Section 4.4.2 and 4.4.3).

5.1.5 Audit

The audit provides a high-level compliance screening against IGEM/TD/13 to identify deviations or constraints that may affect the repurposing or require mitigation.

Many existing installations were designed and constructed prior to the publication of IGEM/TD/13 or its subsequent editions. As a result, full compliance with current requirements may not be demonstrable based on original design and construction standards.

The audit is based on site documentation, records, and verification of the installed configuration against applicable IGEM/TD/13 clauses. The audit shall identify and record compliance against applicable clauses of IGEM/TD/13 Edition 3, using the Section 16 Design Assessment Checklist in Supplement 1 as the primary basis, and including relevant requirements from the core standard and applicable supplements, as appropriate to the installation configuration and repurposing scope.

Where compliance cannot be demonstrated at the audit stage, the identified issues shall be addressed through the detailed design and condition assessment, integrity status assessment, and functionality and operability studies in Sections 5.2 to 5.4.

5.2 Design and Condition Assessment

The design and condition assessment evaluates the suitability of the existing installation design, materials, and condition for the proposed hydrogen operating conditions and identifies any required modifications.

Where assumptions have been made due to incomplete records, these shall be validated as part of the design and condition assessment. Any judgement should be independently validated.

IGEM/TD/13 Supplement 1 Section 16 Design Assessment Checklist is applied as part of this assessment to support the engineering evaluation of the installation for hydrogen service. The checklist shall be reviewed for applicability to ensure that all relevant requirements are identified.

Where material compatibility is a consideration, the ACT described in Appendix C should be used to inform the assessment.

It is recognised that pressure-containing systems are not leak-free in practice. Minor fugitive emissions may occur in natural gas service and are typically identified and managed through established inspection, leak detection, and maintenance arrangements developed through long operational experience. For hydrogen service, given the increased propensity for leakage, greater understanding of containment performance is required. Inspection, leak detection, and maintenance arrangements shall be reviewed and revised as necessary to establish a hydrogen-appropriate containment management regime.

5.2.1 Location and Layout

The location and layout of the installation shall be reviewed to confirm suitability for hydrogen service. The assessment shall consider:

- Installation location and surroundings, including proximity to occupied areas, third-party activities and adjacent infrastructure, to ensure that the consequences of a hydrogen release remain acceptable.
- Ventilation and pipework congestion, ensuring the layout does not promote the accumulation of hydrogen, particularly within enclosed or partially enclosed areas.
- Hazardous areas and separation, ensuring that equipment spacing, vent/relief locations and boundaries remain appropriate for the hazardous area classification (see Section 5.2.13), and that hazardous zones do not extend into unacceptable areas, to confirm that a release from one item would not lead to unacceptable consequences elsewhere on the installation.
- Escalation potential, including interaction between equipment, inventories and release scenarios.

Where risks are identified, these shall be addressed through the installation risk assessment process, with modifications implemented where required.

5.2.2 Pipework and Fittings

The following considerations apply when assessing pipework and pressure-retaining fittings:

Confirm that pipework wall thickness, material grade and design factor remain suitable for the proposed hydrogen operating conditions. Note that IGE/TD/9:1975 limited the design factor to 0.5. IGE/TD/9:1986 introduced varying design factors up to 0.67 based on whether a site is manned or unmanned, protection against external interference, and area type. These principles have been carried through to IGEM/TD/13 Edition 3.

Confirm that fittings and any flanged components connected to the pipework are rated appropriately for the installation pressure.

Confirm whether any existing pipework stress or fatigue analysis for the installation remains valid for hydrogen service. Where no analysis exists, a stress and fatigue analysis should be completed in accordance with IGEM/TD/12 Edition 3 [51] and the requirements of IGEM/TD/13 Supplement 1 unless an engineering-based risk assessment demonstrates that the installation is suitable for the expected loadings and duty.

Where appropriate, a screening assessment may be developed and used to demonstrate suitability. The basis for any decision shall be justified and documented.

Confirm that special fittings (e.g. insulation joints, fabricated tapers) are identified and assessed for suitability.

Confirm that the hydrostatic test pressure complies with IGEM/TD/13 Edition 3. Where installation-specific hydrostatic test records are unavailable, evidence of factory hydrostatic testing of skid units and/or pressure testing of associated pipework may be used. The installation operational pressure history provides supporting evidence of pressure containment capacity. Where evidence is insufficient, further assessment shall be undertaken, which may include revalidation hydrostatic testing or an alternative fitness-for-purpose justification. Where revalidation hydrostatic testing is considered, further guidance on pressure testing of in-service equipment is provided in Section 5.2.5.

Confirm that pipework sizing and flow velocities remain acceptable for the proposed hydrogen flow conditions.

Previous service history of installation pipework shall be reviewed to identify any exposure to manufactured gas. Where such service is identified or cannot be discounted, the potential for existing ISCC shall be considered within the integrity assessment (see Appendix D). Where it can be demonstrated that manufactured gas has not been transported, ISCC is not considered a credible threat.

Where welding records are incomplete, construction predates modern inspection practices, or inspection history indicates potential weld concerns, further assessment or inspection shall be undertaken as appropriate (see Section 4.3.7 and Appendix E).

5.2.3 Gas Cleaning and Filtration

Gas cleaning and filtration systems shall be assessed to confirm their suitability for hydrogen service and protection of downstream equipment.

Confirm that existing filtration systems have sufficient capacity to adequately remove particulates to protect downstream equipment (e.g. regulators, valves and metering systems) under the proposed operating conditions.

Confirm that the differential pressure across filters remains acceptable for hydrogen flow conditions, recognising that lower density and increased velocities may result in higher pressure losses.

Confirm that filter housings, elements and internal components are suitable for hydrogen service and not susceptible to degradation or loss of performance.

Confirm that the condition and operational history of filtration systems support continued operation in hydrogen service.

5.2.4 Isolation Valves

Undertake a review of achievable isolation standards in accordance with HSG253 [52].

Confirm that the isolation arrangement provides double block and bleed (DBB) or single block and bleed with positive isolation i.e., blank or blind flange to be installed when opening isolated equipment, or an equivalent isolation capability. Double block isolation of equipment may be achieved using two valves in series with a vent between or a single body double block and bleed valve.

Where DBB arrangements cannot be achieved, equivalent isolation risk reduction shall be demonstrated and justified.

The functionality of single block valves where reliance is placed on internal sealing to achieve isolation will need to be assessed and justified as required. Valve seat and sealing arrangements should be reviewed when evaluating internal and external leakage performance in hydrogen. The consequences of internal leakage and external leakage should be considered separately, as the associated hazards and mitigations may differ.

Maintenance records shall be reviewed to confirm reliability of closure, evidence of seat integrity, and actuator performance during natural gas service. Particular attention shall be given to historical seat leakage, stem seal performance, and frequency of intervention. Where records are incomplete, or where repeated leakage or maintenance intervention is evident, further inspection, refurbishment, or replacement shall be considered as part of the repurposing assessment.

Confirm any actuator, gearbox, or positioner associated with the valve is suitable for operation under the proposed differential pressures and remains compatible with the hydrogen related hazardous area classification. Consideration should be given to the suitability of the actuation medium (including hydrogen where applicable), venting arrangements and failure modes for gas power actuators.

5.2.5 Pressure Vessels

Equipment classified as pressure vessels are those designed and fabricated to a pressure vessel standard. Pressure vessels include pig traps, filters, gas reservoirs/storage reservoirs/slam shut reservoirs. The standards applicable to pressure vessels have changed over the development of the LTS. Earlier pressure vessels were designed to BS 1515 (IGE/TD/9:1975), BS 5500 (IGE/TD/9:1986), PD 5500 (IGE/TD/1), PD 5500 or BS EN 13445 (IGEM/TD/13 Edition 2), and more recently BS EN 13445, PD 5500 or ASME VIII (IGEM/TD/13 Edition 3). Pressure vessels shall also comply with the Pressure Systems Safety Regulations (PSSR) 2000 [53]. Where applicable, pressure vessels may have been designed and manufactured in accordance with the Pressure Equipment (Safety) Regulations 2016 (PESR) [54]. However, these regulations apply to new equipment and do not generally apply retrospectively.

Where available, information from the original manufacturer of the pressure vessel or a successor organisation holding the technical records should be reviewed to support the assessment for the repurposed operating conditions. This should include review of original design specifications (e.g. BGC/PS/PV/3 or equivalent legacy specifications), drawings and fabrication records where available. Where such information cannot be obtained, fitness-for-purpose assessment shall be undertaken.

The assessment shall consider all relevant degradation mechanisms, including closures and sealing arrangements, and shall explicitly address both historical and future fatigue loading. Where cyclic loading is identified, a fatigue assessment shall be undertaken that accounts for the effects of hydrogen on fatigue performance, including fatigue crack growth behaviour and any reduction in effective fracture toughness. Fitness-for-purpose assessments should consider local stress effects at geometric discontinuities (e.g. nozzles, branches and supports) where relevant.

Where material properties, fabrication quality or defect tolerance are uncertain (e.g. legacy or cast vessels), conservative assumptions shall be adopted and the implications for fatigue performance and fracture resistance shall be considered within the assessment.

Where revalidation hydrostatic testing of in-service pressure vessels is considered, recognised industry guidance (e.g. EEMUA Publication 168 [55] and 223 [56]) should be taken into account.

The technical basis for acceptance or replacement shall be fully documented.

5.2.6 Heating and Cooling

Hydrogen has a small, negative Joule–Thomson coefficient at typical operating temperatures compared with a positive and measurable Joule–Thomson coefficient for methane. As a result, pressure reduction in natural gas service is associated with a temperature decrease, commonly requiring the use of pre-heating to avoid unacceptably low outlet temperatures.

For hydrogen, the negative Joule-Thompson coefficient results in a slight temperature increase during steady state pressure reduction at normal operating temperatures, generally negating the need for pre-heating. The temperature rise is not sufficient to cause ignition [57]. As an example, a pressure reduction of 30 bar would be expected to result in a temperature increase of approximately 1 °C.

The expected temperature change across an installation should be assessed and documented. Where preheating equipment is demonstrated to be unnecessary for hydrogen service, it shall be decommissioned and removed, with the modification documented.

5.2.7 Regulators

Confirm that regulators have not been operated outside their design limits during natural gas service by review of historical pressure and flow data.

Confirm that a suitable maintenance regime has been applied during natural gas service, taking into account OEM recommendations and any risk-based or reliability-centred maintenance strategies. Particular attention shall be given to components subject to time-dependent degradation (e.g. seals, diaphragms and elastomers), as degradation may not be apparent during normal operation.

Where records are incomplete or maintenance practices are unclear, additional inspection, condition assessment or replacement of time-dependent components shall be considered as part of the repurposing.

5.2.8 Protective Devices

Protective devices are provided to prevent equipment or downstream systems being subjected to pressures outside their safe operating limits or specific regulatory limits under fault conditions. For LTS installations, protective devices typically include slam shut valves, monitor regulators, and pressure relief valves, arranged to provide primary and secondary protection.

Confirm that the original protection philosophy remains valid for the proposed hydrogen service. This should include review of set points, response characteristics, redundancy and independence of protective functions, taking account of differences between natural gas and hydrogen, including gas density, compressibility, and leak characteristics.

Protective devices should be examined, tested and maintained in accordance with their WSoE. Historic inspection, testing and maintenance records from natural gas service should be reviewed to confirm that devices have operated within their design limits and any remedial actions are complete. Where records are incomplete or maintenance practices are unclear, additional inspection, testing or replacement should be considered as part of the repurposing assessment.

Slam Shut Valves

Confirm that the design, materials of construction and as-installed condition of the slam shut valves are suitable for hydrogen service at the proposed operating conditions.

Historical pressure data may be reviewed to confirm that slam-shut valves have not been exposed to operating pressures outside their original design limits during natural gas service.

It shall be confirmed that OEM operation and maintenance instructions have been followed during natural gas service. Particular attention shall be given to components subject to time-dependent degradation (e.g. seals, diaphragms, springs and elastomers), noting that degradation may not be apparent during normal operation.

Where records are incomplete or maintenance practices are unclear, additional inspection or replacement of time-dependent components shall be considered as part of the repurposing process.

Where slam shut valves are relied upon as a primary protective measure, their integrity and reliability should be demonstrated.

Where evidence of performance in hydrogen service is limited, additional validation, testing or conservative assumptions shall be adopted to demonstrate reliability in hydrogen operation.

Monitor Regulators

Monitor regulators should be assessed in accordance with Section 5.2.7.

Pressure Relief Valves

Pressure relief valves and associated relief systems shall be assessed to confirm that their design, materials of construction and as-installed condition are suitable for hydrogen service at the proposed operating conditions.

It shall be confirmed that the relief device type and configuration remain appropriate, noting that non-venting pressure safety systems are preferred in accordance with IGEM/TD/13 Edition 3.

The original design basis shall be reviewed, including set pressure, allowable overpressure, rated capacity and applicable sizing assumptions, to confirm compatibility with the proposed hydrogen maximum operating pressure. Where relief devices were designed specifically for natural gas service, confirmation shall be provided that relief performance remains adequate for hydrogen service, or that suitable modifications are identified.

Materials of construction, including pressure-containing parts and time-dependent components (e.g. soft seats, seals and diaphragms where fitted), shall be reviewed for compatibility with hydrogen service.

Where records are incomplete or maintenance practices are unclear, additional inspection, testing or replacement of time-dependent components shall be considered as part of the repurposing process.

Material Acceptability

The materials of construction of protective devices, including pressure-retaining components, internal moving parts, seats, seals and elastomers, should be reviewed for suitability in hydrogen service. Where appropriate, the ACT method described in Section 4.5.3 should be used to inform the assessment of material compatibility.

5.2.9 Control Cabinets

Design and operation of the control cabinets using hydrogen are not known at this stage and it is therefore recommended that a detailed study is commissioned to determine the requirements and the associated design and materials required. Where applicable, it is recommended that standard designs covered by generic documentation are assessed for their suitability in hydrogen service.

5.2.10 Vibration and Noise

Existing vibration and noise assessments shall be reviewed for hydrogen service.

The review shall consider changes in operating pressure, flow rates, gas properties, and transient behaviour that may affect vibration or noise characteristics under hydrogen operation.

Where existing assessments are not representative of the proposed hydrogen operating conditions, additional survey, assessment, or mitigation shall be considered. Particular attention shall be given to locations susceptible to excitation or resonance, in accordance with the Energy Institute guidance [58].

5.2.11 Auxiliary Pipework, Fittings, Gaskets and Bolts

Auxiliary pipework, fittings, gaskets and bolting shall be assessed to confirm suitability for the repurposed hydrogen service.

The assessment shall include consideration of:

- Joint integrity, including flanged, threaded, compression and instrument connections.
- Condition of gaskets, seals and bolting, with particular attention to ageing, degradation, and loss of preload.
- The potential for increased leakage under hydrogen service.

Where records are insufficient, materials are uncertain, or components are not demonstrably suitable for hydrogen service, inspection, material verification, or replacement shall be considered.

5.2.12 Vents and Breathers

Confirmation of vent configuration including the inner diameter, length, and number of fittings (elbows, bends tees) is required to allow assessment of the current venting arrangements and their appropriateness in hydrogen service. The principal measure for the potential of deflagration or detonation inside the vent stack and pipework is the ratio of the length to internal diameter (L/d) which should be below 60:1.

5.2.13 Hazardous Areas

Hazardous area classification forms part of the overall assessment required under Dangerous Substances and Explosives Atmospheres Regulations (DSEAR) [59]. This section focuses on the determination and review of hazardous areas, with the broader DSEAR risk assessment addressed in Section 5.5.

Where hazardous areas extend beyond the installation boundary or into normally occupied areas, the implications shall be considered within the installation risk assessment, and additional assessment (e.g. QRA) may be required.

The IGEM/SR/25 supplement [60] provides a procedure for hazardous area classification around installations handling hydrogen. The supplement should be read in conjunction with IGEM/SR/25 [61].

The hydrogen supplement notes the shapes of the zones around fixtures and fittings should remain the same for hydrogen as those currently used in IGEM/SR/25 for natural gas releases.

For sites being repurposed, it is assumed hazardous area zones have previously been established for natural gas in accordance with IGEM/SR/25 and all equipment items that could be a potential release source have already been identified. These include pipelines, joints, valves, vents, pressure relief devices, small bore fittings, mechanical joints, etc. These existing hazardous areas shall be reviewed and revalidated for hydrogen service, recognising that hazardous zones for hydrogen may extend beyond those previously defined for natural gas.

It is expected that, as a minimum, hazardous area drawings are available for sites explicitly showing equipment items along with zones for natural gas. An associated hazardous area calculation report, for the site, would be a helpful addition to the drawings as this assists with any assumptions, input data and rationale for the calculations. Where such documentation cannot be demonstrated, a full hazardous area assessment shall be undertaken.

Key steps to determine hazardous areas are as follows:

Define system and boundaries:

- Identify the extent of the installation to be assessed (i.e. all equipment within scope)
- Establish operating parameters; pressure, temperature, gas composition
- Define physical boundaries and any adjacent occupied or restricted areas.

Identify potential sources of release:

- Identify all components that could release gas such as joints, flanges, seals, fittings, pressure relief devices and vents and connections to equipment and instrumentation
- Consider releases during normal and abnormal operation.

Categorise the release type:

- Continuous – release present continuously for long periods
- Primary – release likely during operation
- Secondary – release not expected during normal operation, i.e. occurs infrequently

This categorisation underpins the subsequent zone classification.

Consider release characteristics:

- System pressure
- Pipe diameter
- Size and nature of release (e.g. pinhole, joint failure).

Assess ventilation conditions:

- Natural (outdoor, open sides)
- Restricted (partially enclosed, congested area)
- Forced (mechanical ventilation).

Determine Hazardous Area Zones:

- Using the release type and ventilation assessment assign the appropriate zone (Zone 0, 1 or 2)
- Determine the horizontal and vertical extent of each zone.

5.2.13.1 Define risk reduction and mitigation measures

Where hazardous areas extend beyond a site boundary or into a normally occupied area, consider design changes such as:

- Change type of equipment e.g. reduce the number of joints, and/or fittings where appropriate
- Relocate or change type of vents (e.g. non-ideal to ideal or move vent to a non-congested area and/or away from a site boundary)
- Relocate normally occupied areas.

In addition to calculating hazardous zones, it is also important to consider potential changes to inspection requirements. The methodology for calculation of the release rate of hydrogen is given in IGEM/SR/25, with the exception that the likely increase in failure frequency for hydrogen depends strongly on the materials used. The failure frequency given in IGEM/SR/25 for each component item is to be multiplied by a materials factor for that component as listed in the hydrogen supplement, where materials are gas facing under normal operation. Any increase to the 'frequency of failures per year' will cause a decrease in the required Maximum Zone 2 time between inspection outlined in IGEM/SR/25. For this reason, detailed equipment records (drawings and operations and maintenance manuals) are particularly beneficial to enable consideration of the materials.

5.2.13.2 Change in zone distances for each natural gas and hydrogen

There is no general rule that can be applied to provide indicative changes to hazard distances for all equipment types at sites. IGEM/SR/25 provides look up tables for various equipment configurations operating at various pressures and gas flow rates. Whilst there are too many to include here, Table 5.3 is provided to illustrate the difference that each of the gases make to hazard zone distances. Each comparison uses data from IGEM/SR/25 and from the information in the associated hydrogen supplement and is only shown for >30 and <50 bar operating pressure (as currently the existing LTS above ground installations are expected to operate with natural gas within that pressure range). Table 53 is only to show differences between gases for similar installation equipment, and it should be noted there are many more variations of equipment shown IGEM/SR/25 and the associated hydrogen supplement.

The values in Table 53 are indicative for typical ('standard') operating conditions and are provided for comparison purposes only. In practice, hazardous area extents will vary depending on installation specific conditions and should be determined using IGEM/SR/25 and the hydrogen supplement.

Table 5.3 - Comparison of Zoning Distances for Equipment Under Natural Gas and Hydrogen

Equipment	Natural Gas	Hydrogen
Outdoors freely ventilated installation under normal conditions	1.0 m	4.5 m
Outdoors congested or confined conditions	1.5 m	4.5 m
Ideal vent pipe nominal diameter 50mm with flow rate 1kg s^{-1} (Extent of the hazardous area surrounding vent drain holes Xc)	3.01 m	16.61 m
Ideal vent pipe nominal diameter 50mm with flow rate >1and<2 kg s^{-1} Ideal vent pipe terminations horizontal Xr/vertical Xh distances.	Xr = 6.0 m Xh = 25.0 m	45 m 100 m
Ideal vent pipe nominal diameter 100mm with flow rate >1and<2 kg s^{-1} Ideal vent pipe terminations horizontal Xr/vertical Xh distances.	Xr = 12 m Xh = 35 m	50 m 100 m
Non-Ideal impeded vent pipe nominal diameter 50mm with flow rate >1and<2 kg s^{-1} vent pipe terminations dispersion radius	X = 35 m	110 m
Non-Ideal impeded vent pipe nominal diameter 100mm with flow rate >1and<2 kg s^{-1} vent pipe terminations dispersion radius	X = 60 m	110 m

5.2.13.2 Learnings from case studies

Learning from case studies has shown hazardous zones for hydrogen can extend significantly further than existing natural gas zones and, in some cases, either extend beyond the site boundary or into unwanted areas such as pathways or occupied buildings. Where this occurs, measures to reduce risk must be considered including:

- Making the item suitable for hydrogen service e.g. through replacement.
- Changing the design type of equipment item to reduce the zone – e.g. replace a non-ideal vent for an ideal vent may reduce the radius of the zone.
- Relocating the equipment item to say a freely vented area or away from a site boundary.
- Changing the design of the operation.
- Restricting flow rates and/or pressures.
- Reducing ignition source risks within areas adjacent to hazardous zones.
- The correct use of suitably zone rated electrical equipment.

The design of any equipment should be assessed for the potential of deflagration or detonation of a hydrogen-air mixture inside the vent stack – the number of turns and connections should be minimised and the L/d ratio shall be below 60:1 to prevent such an event.

Due to experience of limited records of equipment at sites, it may be eminently more practical to replace equipment items to ensure they are suitable for use with hydrogen. Any replacements should follow an appropriate risk assessment methodology. This removes unknowns in the material properties and condition of the equipment (with potentially unknown service).

5.2.14 Metering, Gas Analysis and Odorisation

Metering, gas analysis and odorisation systems shall be identified and assessed to confirm their suitability for hydrogen service at the proposed operating conditions.

Metering systems shall be assessed to determine whether existing equipment can be repurposed for hydrogen service, considering material compatibility, pressure containment and the ability to provide accurate and reliable measurement. This shall include consideration of measurement uncertainty, hydrogen-specific flow characteristics, conversion algorithms and compliance with relevant hydrogen metering standards for operational and fiscal purposes.

Gas analysis systems shall be assessed to confirm that measurement principles, sampling arrangements and associated instrumentation are suitable for hydrogen service, and capable of accurately determining hydrogen concentration and other relevant gas constituents. Consideration shall be given to the impact of hydrogen on sensor performance, response and calibration.

Odorisation systems shall be assessed in the context of the required gas specification and end-user requirements. This shall include consideration of odorant storage, injection and control systems, material compatibility (including seals and elastomers), and system performance under hydrogen service conditions. Any fluids used within the system (e.g. blanket gases) shall be reviewed for compatibility and suitability.

It is recognised that existing gas analysis and odorisation systems are unlikely to be suitable for hydrogen service. Where this is the case, replacement or redesign shall be considered, and new systems shall be selected based on the required hydrogen gas specification and end-user requirements. The LTS Futures live trial implemented new odorisation and metering systems designed for hydrogen service.

Where system suitability is uncertain, additional validation, testing or conservative assumptions shall be adopted to demonstrate suitability.

5.2.15 Corrosion Protection

Where suitably recent records of accessible component and pipework condition are unavailable, visual inspection shall be performed to confirm coating condition and identify any corrosion damage.

The integrity of buried or otherwise inaccessible components and pipework shall be assessed. This may require exposure where justified by risk.

Effectiveness and maintenance of any CP systems shall be confirmed, including review of historical performance to demonstrate adequate potential levels.

Further guidance on the assessment of external corrosion of buried pipework, including use of CP performance data and CIPS/DCVG results to inform remaining life, is provided in UKOPA/GP/018 [62].

CP may result in hydrogen evolution at the steel surface which is normally controlled through current regulation. Hydrogen evolution at the steel surface may promote coating disbondment. CP is a known contributor to hydrogen embrittlement in carbon steels. It is not fully understood whether hydrogen service may accelerate these mechanisms, therefore additional monitoring and assurance shall be considered.

5.2.16 Electrical and Instrumentation

Instrumentation shall be assessed for suitability in the proposed hydrogen service. This includes considering re-ranging, re-calibration, testing or replacement where instrumentation performance is affected by changes in gas properties, operating envelope, or system function.

Instrumentation should be considered as part of the wider system, including upstream and downstream process interfaces, alarm functions and control logic.

The requirements for ATEX equipment in hydrogen is Equipment Group IIC, compared with IIA in natural gas. A detailed site survey is required to positively identify each asset, the associated explosion group rating and suitability for hydrogen.

Potential impact on power supplies, uninterruptible power systems, battery-backed systems, cabling and communications should be assessed, particularly where loss of power could adversely affect installation functionality.

Where standby power generation relies on natural gas, the continued suitability of the arrangement under hydrogen service should be assessed, or alternative arrangements considered.

For hydrogen service it is recommended that leak and flame detection devices are installed at appropriate locations. The selection and location of leak and flame detection shall be defined, taking into account potential release sources, ventilation conditions, hazardous area classification and equipment congestion.

The LTS Futures Project employed ultrasonic gas leak detection to identify airborne ultrasound generated by pressurised gas leaks. Such ultrasound is produced as gas expands from a higher-pressure region to a lower-pressure region. The project also utilised multi-spectrum infrared flame detection, which analyses signals across multiple infrared bands to detect flames. Experience from the project demonstrated the importance of commissioning, validation and appropriate configuration of detection systems to ensure reliable performance in hydrogen service. In particular, consideration should be given to background conditions, potential sources of spurious alarms, and the need for initial tuning or stabilisation periods following installation. Alarm settings and filtering should be configured to minimise nuisance alarms while maintaining effective detection, and the end-to-end functionality from detection through to alarm and operator response should be verified.

5.2.17 Signage and Demarcation

Existing signage should be identified and assessed to confirm that it is suitable for hydrogen service or requires updating.

Signage should clearly identify hydrogen service and communicate relevant hazards, including flammable and pressurised gas. The extent and type of signage should be proportionate to the installation and informed by site-specific risk assessment and health and safety guidance.

Site signage shall reflect hazardous area classification and clearly communicate controls on ignition sources, including restrictions on non-ATEX electrical equipment.

Required personal protective equipment (including anti-static and flame-retardant PPE where specified by risk assessment) shall be clearly identified at site access points.

Clear demarcation should be provided where an installation contains both natural gas and hydrogen assets.

5.2.18 Buildings

Where possible all installations operating in hydrogen service should be located outside to allow good natural ventilation.

Buildings that are to remain in hydrogen service shall be assessed for ventilation taking account of the rate of pressure increase, increased buoyancy and faster dispersion.

Ventilation assessment shall be undertaken in accordance with IGEM/SR/25, IGEM/TD/13, and IGEM/TD/13 Supplement 1. It shall not be assumed that prescriptive ventilation provisions developed for natural gas service are necessarily sufficient for hydrogen service, and adequacy shall be confirmed through the installation risk assessment.

Where hydrogen service results in increased hazardous area extents or overpressure risks, enhanced ventilation or alternative design measures shall be considered.

Building assessment should confirm structural and civil integrity.

5.2.19 Pipe Supports

The condition and configuration of all pipe supports shall be assessed to confirm structural integrity and continued fitness for service. The assessment shall include all permanent pipe supports, including associated steelwork, fixings, and foundations.

Attention shall be given to susceptible locations including the air–soil interface and support contact points where corrosion or degradation may occur.

Pipe supports shall be reviewed to confirm they provide the intended restraint and allow any required pipe movement. Evidence of seized, damaged, or over-restrained supports shall be identified.

Pipe supports shall be confirmed as suitable for applied loads including pipe weight, thermal effects, and any planned modifications for repurposing.

5.2.20 Software

Software used for control, monitoring, protection, and measurement shall be confirmed as suitable for continued and repurposed service. Software configuration, version status, and support shall be reviewed. Where changes in gas properties, operating conditions, or site configuration occur, affected software shall be revalidated and recalibrated as required.

5.3 Integrity Status

The integrity status assessment shall confirm the current integrity of all pipework, vessels and equipment considered for repurposing, using the outputs of the design and condition assessments in Section 5.2. The assessment shall determine whether any identified integrity issues, including hydrogen-specific degradation mechanisms, could affect suitability for hydrogen service.

The integrity status assessment shall summarise the integrity status of all pressure-retaining and load-bearing components within the defined scope of the installation and shall summarise, as a minimum:

- The status and acceptability of any temporary or permanent repairs, and their suitability for continued service under the proposed hydrogen operating conditions.
- The condition of exposed pipework and vessels, including any identified damage, coating degradation, deformation, or evidence of external interference.
- The status of external corrosion control for buried, inaccessible or partially accessible pipework, based on review of corrosion protection performance and inspection records.
- The condition and adequacy of civil and structural elements supporting pressure-retaining equipment.

The integrity status assessment shall consider hydrogen specific degradation and failure mechanisms, including susceptibility to hydrogen embrittlement and increased leakage propensity.

The assessment shall identify any integrity concerns requiring remediation, further investigation, operational constraints, or assumptions requiring validation prior to repurposing for hydrogen service.

5.4 Functionality and Operability Studies

Functionality and operability are normally demonstrated using existing natural gas operation, testing and historical performance, supplemented where necessary to address hydrogen-specific behaviour. Functionality and operability studies shall confirm that control, protection, detection, and operational interaction remain effective and practicable under hydrogen service across all intended operating conditions.

The studies shall focus on system behaviour, control, SOL protection, hydrogen detection, and human interaction.

5.4.1 Operating Conditions

The ability of the installation to operate within the proposed hydrogen operating envelope shall be assessed, including:

- Minimum and maximum operating pressures
- Flow rates and velocities
- Start-up, shutdown, and commissioning conditions
- Transient events (demand changes, trips, isolation).

Any differences in behaviour compared with natural gas service shall be identified and documented.

5.4.2 Regulators

The performance of pressure regulators shall be reviewed to confirm stable and predictable operation in hydrogen service, including:

- Pressure control stability and response
- Interaction between active, monitor, and protective devices
- Set points, dead bands, and rate-of-change effects
- Reset and recovery following trips or shutdowns.

Where historical operational data is unavailable or not representative, additional testing or conservative assumptions shall be applied.

The assessment should consider the impact of hydrogen service on regulator performance, including changes in gas properties affecting flow capacity, pressure control characteristics, noise, vibration, and wear rates, particularly where higher velocities or large pressure reductions occur.

Potential reduction in regulator stability if the inlet to the impulse line is in a location affected by pressure variations caused by turbulence and flow instability. Regulators which are stable for natural gas may not be stable for hydrogen.

5.4.3 Protective Devices

The functionality of protective devices shall be assessed under hydrogen operating conditions, including:

- Slam shut valve actuation behaviour and closure speed
- Interaction with upstream and downstream pressure control equipment
- Pressure transients generated by protective device operation
- Practicality and safety of testing and resetting.

The consequences of protective device operation shall be considered as part of overall system operability.

Slam Shut Valves

Slam shut valves shall be assessed to confirm continued suitability to provide over-pressure protection in hydrogen service.

Set points, accuracy class, actuation mechanisms and impulse lines shall be confirmed suitable for the repurposed hydrogen operating envelope.

Failure modes, including leakage (let-by) and its impact on downstream pressure control and protection, shall be reviewed.

Where relied upon as a primary protective measure, integrity and reliability shall be demonstrated.

Monitor Regulators

Monitor regulators should be assessed to confirm that set points, lock-up performance and accuracy classes provide adequate separation from active regulators, there is sufficient capacity to control pressure under fault conditions. Changeover behaviour and stability remain acceptable for hydrogen service, interactions between active, monitor and slam shut devices do not compromise protection.

Pressure Relief Valves

Non-venting pressure safety systems are preferred under IGEM/TD/13 Edition 3.

Pressure relief valves and associated relief systems should be assessed to confirm suitability for hydrogen service, including relief capacity and set pressure relative to maximum operating pressure, discharge characteristics and assumptions used in sizing, discharge routing, vent termination and dispersion, with due consideration of hydrogen buoyancy and ignition risk.

Confirmation should be provided that relief performance remains adequate for hydrogen or that modification is identified.

5.4.4 Metering

Metering performance and accuracy under the proposed hydrogen operating envelope shall be reviewed, including the impact of flow regime, velocity and gas properties.

Hydrogen service may introduce different flow characteristics compared with natural gas, including higher volumetric flow rates and increased sensitivity to flow regime and installation configuration effects. Meter suitability and sizing should therefore be assessed against the intended hydrogen operating envelope.

Where existing metering equipment cannot be demonstrated to be suitable for the repurposed conditions, options such as re-rating, modification or replacement should be considered and supported by appropriate technical justification.

5.4.5 Leak Detection and Alarms

Detection and alarm systems shall be reviewed to confirm that leaks and abnormal operating conditions can be reliably detected and communicated, including:

- Gas and flame detection coverage and response
- Pressure, temperature, and rate-of-change alarms
- Local and remote alarms
- Assumptions regarding manned and unmanned operation
- Alarm setpoints, prioritisation and operator response arrangements, including suitability for hydrogen service and associated operating conditions.

Hydrogen flame visibility and dispersion behaviour shall be explicitly recognised.

Alarm systems and associated response arrangements shall be validated under representative operating conditions to ensure reliable performance, including minimisation of spurious alarms and appropriate operator response.

5.5 Installation Risk Assessment

Installations designed to IGEM/TD/13 with hazardous areas that are within the installation boundary do not typically require QRA. However, QRA may be undertaken where required based on site-specific conditions or where standard design assumptions are not met.

Where modifications or redesign of installations are undertaken, appropriate hazard identification and risk assessment studies (e.g. HAZID, HAZOP) shall be completed in accordance with relevant standards.

If the hazardous areas for hydrogen operation also do not extend beyond the fence line of the installation, it is recommended that full QRA is not required.

If QRA is required, the installation risk assessment shall evaluate the risks associated with operating the installation in hydrogen service, taking account of the defined scope and proposed operating conditions. Consideration should be given to the effect of hydrogen embrittlement on fracture toughness and fatigue crack growth in determining appropriate failure frequencies. The effect of overpressure on site personnel, members of the public and equipment must also be considered.

The risk assessment shall be informed by the outcomes of the design and condition assessment, integrity status, and functionality and operability studies.

Hydrogen specific hazards and characteristics shall be explicitly considered.

The risk assessment shall be used to demonstrate that risks associated with hydrogen service are reduced to ALARP and to identify any additional mitigation, operational constraints, monitoring, or modifications required prior to repurposing.

It is recognised that, while assessments can demonstrate suitability for hydrogen service, confidence in longer term performance will be established through operational experience. Appropriate monitoring, inspection and maintenance (including functional test) regimes should be implemented (with adequate records kept) to support this, including consideration of the reliability and effectiveness of safety and control systems and their ability to perform as intended.

5.5.1 The Dangerous Substances and Explosive Atmospheres Regulations 2002

The installation risk assessment shall address the requirements of the Dangerous Substances and Explosive Atmospheres Regulations 2002 (DSEAR) [59].

Site specific DSEAR risk assessments shall be carried out to identify and classify areas of the installation where explosive atmospheres may occur and avoid all types of ignition sources, mechanical, electrical and operational. All employees should be made aware of the DSEAR risk assessment and be trained to control or deal with the risks from hydrogen operation including emergency responses.

A hazardous area classification drawing must be produced for all installations.

DSEAR risk assessments and hazardous area classifications were undertaken for each installation as part of the LTS Futures Project live trial.

5.6 Installation Safety Justification

The installation safety justification shall bring together the outputs of the design and condition assessment, integrity status assessment, functionality and operability studies, and installation risk assessment to demonstrate that the installation is suitable for operation in hydrogen service.

The safety justification shall document the basis on which the installation is considered fit for hydrogen service, including identified risks, applied mitigation measures, operational constraints, and any assumptions requiring validation.

The safety justification shall confirm that risks associated with hydrogen service are ALARP and that any conditions for repurposing are clearly defined prior to change of service.

5.6.1 Asset and Infrastructure Details

Confirmation that all asset records have been updated to reflect hydrogen service, including any changes arising from the repurposing works, including:

- Asset registers, drawings and associated records
- Confirmation that signage, demarcation and hazardous area information are appropriate for hydrogen service and have been installed in accordance with applicable requirements.

5.6.2 Modifications

Confirmation that all documentation associated with modifications required for hydrogen repurposing is complete including:

- Modifications details
- Confirmation of design, installation, testing, completion and approval in accordance with IGEM/GL/5 or equivalent
- All records and drawings have been updated to reflect the as-modified installation.

5.6.3 Risk Mitigation

Document that any risk mitigation measures implemented to ensure risks associated with hydrogen service are reduced to ALARP, including:

- Details of risk mitigation measures required
- Confirmation of installation, completion and approval
- Residual risk identification and the acceptance basis.

5.6.4 Revalidation

Address revalidation requirements arising from repurposing, including:

- Assessment of any changes to safety factors or operating conditions
- Confirmation that revalidation activities have been completed, checked and approved where required.
- Identification and validation of assumptions relied upon in the assessment.

5.7 Installation Hydrogen Repurposing Report

The Installation Hydrogen Repurposing Report shall record the final decision on whether the installation is suitable to be repurposed for hydrogen service. The report shall:

- Confirm the defined scope of the installation and the intended hydrogen operating conditions.
- Confirm that the installation safety justification has been completed and approved.
- Confirm that all technical requirements for repurposing have been satisfied, or that any outstanding issues are subject to defined conditions or constraints.
- Record the final decision to accept the installation for hydrogen service, accept it subject to specified conditions, or reject it pending further work.
- Record the authority and basis for the decision.

6 Implementation, Assurance and Handover

6.1 Network Operation Review

A series of Network Operation Reviews (NOR) should be carried out as the repurposing process for the individual pipeline and installations are carried out. The purpose of these reviews is to understand and document the end-to-end operation of the hydrogen network and consider the safe operation of the network from hydrogen suppliers through to the customers connected to the network. As a minimum a NOR should be carried out before individual viability studies are started, after the completion of the viability study, prior to modifying any pipeline or installation and following the final repurposing reports. NOR's should be attended by representatives from the design, construction, operation, control, network management and emergency response managers and staff and be chaired by a process engineer.

The NOR shall consider the end-to-end process and include the following:

- Gas quality and odorant management
- Hydrogen production and storage
- Customer minimum requirements
- System monitoring and control (SCADA)
- Pressure and flow control
- Over-pressure and under-pressure monitoring and protection
- Emergency Procedures.

All actions associated with the NOR shall be documented and tracked to closure. The final NOR report will be used to assess whether the overall system is ready for operation with hydrogen.

6.2 Stakeholder Engagement

Engagement with key stakeholders should start as early in the planning process as possible and continue throughout the project. A communications plan is helpful for managing the process and ensuring that each stakeholder receives the information they require at the right time and are invited to engage in relevant round table and stakeholder events. Both external and internal stakeholders will need to be engaged in a series of workshops, group and individual meetings. For the SGN live trial the following Stakeholder groups were key:

- **HSE liaison and formal regulatory notifications**. Pipelines Safety Regulations (PSR) notifications are required if a pipeline is being brought into operation (Reg 21 – notification before use / re-use (minimum of 14 days prior to the fluid being introduced)) and before change of use of a pipeline (Reg 22 (2)) Other which includes change of fluid (minimum of three months prior to the fluid being introduced)) although liaison with the HSE from the conception of the project is recommended. Regular update meetings may also prove useful.
- **Other operators:** Where pipelines or installations interface with, or are located within, sites subject to other regulatory regimes (e.g. Hazardous Substances Consent (HSC) or Control of Major Accident Hazards (COMAH), these should be identified and considered as part of the repurposing assessment, recognising that site-level regulatory requirements are managed by the site operator. Engagement with the site operator and relevant regulatory bodies should be undertaken as appropriate.
- **Landowners** - Communication with landowners is essential with regard to existing servitudes for pipelines and a review of these is required to check if they reference gas or natural gas and their resulting suitability for use with hydrogen. It is important to remind landowners of pipeline positions and their responsibilities regarding these, such as safe digging practices etc. The LTS futures project took this opportunity to communicate physical surveys that would be carried out as part of the repurposing.
- **Local Authorities** - provide a key link into communities via councillors and therefore communications with them are important throughout any project/repurposing. During the LTS Futures trial this was particularly usefulwhen progressing planning applications and street works which required traffic management. This continued engagement was carried through to the updating of emergency response plans including attendance at multi agency workshops.
- **Resilience Partnership** - East of Scotland Regional Resilience Partnership/Emergency Services - Engagement with the Resilience Partnership provided a gateway to collective communications across all emergency services at the required level of authority/responsibility. Due to the large number of organisations involved, using this established partnership led to collaborative emergency planning workshops with all services engaged.
- **Ofgem** – engagement with Ofgem as a regulatory body was important for LTS Futures as the project was novel but with a limited scope and specifically no end users. This enabled a derogation from the Unified Network Code (UNC) for the project. As a key funding provider engagement with Ofgem provided confidence that the project was on track and delivering outcomes as required. Where adjustments were needed, this ongoing relationship ensured that communications were always open and issues discussed.
- **Internal Departments** - engagement with business-as-usual functions within SGN ensured that people were aware of the project and when support was required these departments were engaged for their expertise. The LTS Futures approach to this was to set up several advisory groups early in the project, enabling dissemination of project progress as well as requests for additional support from the relevant specialist areas.

6.3 Emergency Planning and Response

Emergency Planning and Response process and procedures used for natural gas operation will need to be reviewed and updated for hydrogen operation. If the hydrogen network is being odorised, then the revised process and procedure will need to consider the impact of operating an odorised hydrogen pipeline in locations where existing natural gas pipelines are operating with the same or similar odorant. The procedure will need to consider how operatives responding to public reported gas escape are able to differentiate between hydrogen and natural gas and they will need to be provided with a gas detection device that accurately measures gas in air concentrations for both hydrogen and natural gas.

For the LTS Futures project, a dual response approach was adopted for public reported escapes in the area within the vicinity of the hydrogen pipeline. This consisted of a natural gas first response operative and a high-pressure pipeline specialist who had a hydrogen gas detection device being dispatched at the same time. The work procedure was followed to enable the fluid (natural gas or hydrogen) to be identified, and if the escape was found to be hydrogen, the pipeline specialist was already on hand to deal with the emergency.

The management of an incident/leak on a hydrogen transmission pipeline will be similar to that used for a natural gas transmission pipeline by establishing an exclusion zone around the incident/leak and isolating and reducing pressure in the section of the pipeline affected. For the LTS Futures trial the Local Authority Emergency Planning evacuation distance was the same as for natural gas.

6.4 Quality Assurance and Documentation

A well-structured quality assurance (QA) and records management system will be required to support and demonstrate a pipeline/installation is suitable for repurposing for use with hydrogen. The QA system will need to be well resourced with competent records engineers and data analysts who are able to link historical design, construction, maintenance and operational records with the assets being considered for repurposing (see Sections 4.1 and 5.1.1). A structured GIS would assist repurposing engineers overlay pipeline records to ensure all sections of a pipeline has been assessed for use with hydrogen.

The initial stage of a repurposing project will involve the gathering and collating historical records of the asset being considered. These documents will be a mixture of hard and electronic copies; the case studies showed these documents are stored and filed in various locations some were found in project files others were found in a pipeline/installation folder. To enable a pipeline to be repurposed these documents will need to be referenced and linked to the asset being considered. For pipelines a detailed TD/1 MOP Affirmation Audit Report (which should be updated every four years) would provide the basis of the evidence required to justify a pipeline can be considered for repurposing for use with hydrogen. The case studies found the existing processes for TD/1 MOP Affirmation Audits could be significantly improved to prepare for repurposing. To assist the repurposing process all records associated with a pipeline/installation should be stored against a pipeline/installation rather than against a project as is the case with many of the pipeline diversions.

The QA and records management system should be maintained through the lifetime of the project and used to record all investigation works, repairs and modifications required to allow the asset to be repurposed for hydrogen. On completion of the repurposing project the records management system will need to be maintained and updated to continue to demonstrate the asset remains fit for use with hydrogen and be able to inform future inspection and maintenance requirements.

6.5 Appraisal and Approval

All repurposing activities, including modifications, repairs, and any new pipelines or connections to repurposed pipelines or installations, should be subject to independent appraisal and acceptance in accordance with a recognised change management procedure. The appraisal and approval process shall be undertaken by personnel independent of those responsible for the design and execution of the repurposing activities. To enable the introduction of hydrogen an industry standard for management and control of new works, modifications and repairs will need to be developed following similar principles to those detailed in IGEM/GL/5 Edition 3.

IGEM GL/5 scope covers management and control of new works, modifications and repairs to assets associated with the supply of fuel gas such as Natural Gas, Bio-gas (including Biomethane), Liquefied Natural Gas (LNG), Liquefied Petroleum Gas (LPG) and LPG/Air. Whist Hydrogen is currently not included in the scope, similar principals detailed in the standard will need to be applied.

To support the introduction of hydrogen it seems practical to ask IGEM to review the scope of IGEM/GL/5 and update it to include hydrogen.

Repurposing activities shall be undertaken and appraised by suitably qualified and experienced engineers. Where hydrogen specific experience is limited, additional training and competency assessment shall be undertaken. Existing approval frameworks for natural gas shall be reviewed and extended as necessary to include hydrogen.

A pipeline or installation repurposing report will need to be independently appraised and accepted by the owner and the PSSR "user" of the network in accordance with PSSR which requires the PSSR competent person approve change in use and WSoE.

6.6 Approval Process

In preparation for approving the asset for operation with hydrogen the following regulatory documents would need to be developed and approved by the pipeline operator and where required shared with the HSE.

- PSR Major Accident Prevention Document
- Case for Safety for the pipeline operation
- PSSR WSoE.

The HSE will need to be notified of the change of use in accordance with PSR. This should be done at various stages of the project to ensure the HSE have been given opportunity to inspection modifications and repairs to the pipeline/installations and update Land Use Planning.
The final approval to convert the pipeline/installation for use with hydrogen will be carried out by the "user" the following areas have been completed:

- Repurposing Report
- Modifications and repairs
- Signage and notifications
- Inspection and Maintenance Procedures
- Emergency Procedures and Testing
- Training and Competence
- Stakeholder notifications
- Commissioning procedures.

6.7 Change of Service to Hydrogen

Prior to the introduction of hydrogen, it shall be confirmed that the network and organisation are operationally ready for hydrogen service across all relevant functions. This shall include verification that existing arrangements, procedures and competencies have been reviewed and updated as necessary to reflect hydrogen-specific requirements.

Hydrogen shall only be introduced into a pipeline/installation when the change of service has been approved by the "user".

The process required to commission the pipeline/installation for use with hydrogen will depend on the type of gas and pressure in the pipeline prior to converting to hydrogen. If the pipeline/installation has been decommissioned and contains air, then an indirect purge to nitrogen will be required before introducing hydrogen. If the pipeline is pressurised with natural gas or nitrogen, then the pipeline may be directly converted to hydrogen using a flaring facility and by controlling the flow of hydrogen into the pipeline.

Regardless of the method of conversion a detailed commissioning plan will be required with step-by-step actions detailed in a non-routine procedure.

The non-routine procedure shall include detail the requirements for periodic leak checks to be carried out at mechanical joints during the commissioning process and walking surveys. Prior to introducing the hydrogen to the pipeline, the quality of the gas should be confirmed to ensure it is within the agreed specification.

If the pressure in the pipeline is to be increased during the commission process, then the pressure should be raised at increments in accordance with IGEM/TD/1 Edition 6 clause 12.4.3.5 allowing time for leakage survey to be carried out at each increment.

For the LTS Futures live trial, the Grangemouth to Granton pipeline had been mothballed and filled with nitrogen, so the pipeline was purged direct through a flare stack at Granton and the pressure was raised in 7 bar increments allowing for leak surveys to be carried out at all installations along the pipeline.

Following a successful purge and before the pressure is increased, functional checks should be carried out on all protective devices, pressure/flow equipment and instrumentation to ensure they are working correctly. Following completion of the pressure raising operation, functional checks should be repeated to confirm everything is working within tolerances.

If the pipeline is to carry odorised hydrogen, then arrangements should be put in place to measure the odorant levels during the purge and pressure raising process (using both rhinologists and chemical analysis). In some case there may be a need to increase the level of odorant to ensure a new pipeline or installation and/or repurposed pipeline that has been out of service, is thoroughly wetted with odorant.

On completion of the commissioning project the pipeline should be declared operational to the "user" and all emergency arrangements should be put in place and communicated to all stakeholders.

Following commissioning, a report should be prepared and issued to the "user" and retained along with the asset records.

6.8 Post-Change Review and Verification

On completion of the commissioning project a series post change inspections should be carried out to confirm the pipeline and installation/s is/are operating correctly; the frequency of these inspections will depend on the assets being repurposed. Initially it is recommended that the following should be carried out on a daily/weekly basis until confidence everything is operating correctly.

- Leak survey
- Instrumentation (leak/flame detection equipment where installed)
- Function checks on protective devices and pressure control equipment
- Gas quality and odorant equipment if fitted
- Odorant levels
- Noise and vibration.

These additional checks should remain in place until it can be demonstrated that the pipeline/installation is operating correctly and within agreed limits. As a minimum these additional checks should remain in place for six weeks.

There should be a formal review of the pipeline/installation operation 12 months after repurposed operation to confirm that all assets are working correctly and operating within agreed limits. This review should consider and recommend ongoing maintenance and inspection requirements to ensure safe operation of the assets. Following completion of the formal review a report should be prepared and issued to the "user" and retained along with the asset records.

7 Operation and Maintenance

7.1 Maintenance Instructions and Procedures

The maintenance procedures, work instructions and risk assessments which are currently used to operate and maintain the pipelines and installations for natural gas will need to be reviewed and adapted to create equivalent documents and new documents which include the additional risks associated with hydrogen and the changes to the procedures which will be required to work safely. See Appendix B which details the differences between the properties of natural gas and hydrogen.

Whilst a significant proportion of the existing instructions will be similar as those for natural gas, to assist the users to recognise the additional measures required to work safely with hydrogen it is recommended that new hydrogen specific procedures are developed rather than hybrid natural gas/hydrogen documents. It should be noted that there may be additional hazards or operational steps to include and therefore care should be taken to ensure procedures are comprehensive and robust.

The different safety hazards which will need to be taken into consideration when developing procedures and instructions for hydrogen are:

- Increased flammable range - for natural gas the flammable range is 5 % to 15 % gas in air. For hydrogen the flammable range is significantly larger, from 4 % to 75 % gas in air.
- Increased probability of ignition (ignition from static discharge). The minimum energy for ignition of natural gas is 0.26 mJ and hydrogen 0.01 mJ at stoichiometric concentrations.
- Poor visibility of flame in daylight, a hydrogen flame is virtually invisible in daylight, this is particularly an issue where a leak is from above ground pipework. For below ground releases, entrained dust/debris will make the flame visible.
- Greater chance of leakage because hydrogen is a smaller (molecular weight 2.016 mol/g) than natural gas (methane molecular weight 16.042 mol/g).
- Hydrogen is significantly less dense and more buoyant (density 0.0853 Kg/Sm^3) than natural gas (density 0.6785 Kg/Sm^3). Any release of hydrogen is likely to rise quickly.
- Increased flame speed (with the potential for higher overpressures than natural gas where the thermal radiation distances are the dominant effect).
- For Hydrogen only Group IIC or IIB + hydrogen ATEX rated equipment is permitted compared to IIA for natural gas.

The following operational procedures will need to be adjusted or fundamentally altered, and in some cases different tools and equipment will need to be used for hydrogen service:

- Emergency Response including the detection and management of minor leaks
- Isolation, decommissioning sections of pipework or equipment
- Venting, flaring and purging procedures
- P/9 welding procedure (Live pipeline welding)
- Hot tapping and flow stopping procedures
- Instrumentation and electrical procedures.

For the LTS Futures live trial specific procedures were developed for:

- Commissioning and decommissioning
- Flaring and venting
- Emergency Response Procedures
- Critical incident response
- Operational and maintenance procedures for the connection point, entry unit, block valve site, flare site and the pipeline
- Gas sampling
- Work instruction for alarm response actions.

Non-Routine Operation procedures were developed to cover the following operations:

- Purging (nitrogen to hydrogen)
- Entry unit commissioning and pressurisation
- Flow trial for hot work
- Live welding and hot tapping
- Flow stopping – stopple train
- Grouted tee and hot tapping
- Flow stopping – BISEP
- Depressurisation
- Purging (hydrogen to nitrogen).

7.1.1 Personal Protective Equipment (PPE)

The PPE requirements for working with hydrogen are different to that required for natural gas, the key differences are the electrostatic discharge limits which are required for hydrogen. Each GDN will need to review the PPE they use for natural gas to determine if it needs to be replaced with a hydrogen compliant equivalent. There will also be a need to update PPE policies in terms of the requirement on contractors to comply with hydrogen PPE specifications.

SGN carried out a study to identify if their current supply of PPE met the requirements to operate in hydrogen environments, only a few items were identified, such as one type of hi-vis sleeved waistcoat, gloves and boots. The following standards must be met for PPE used in hydrogen environments:

- For clothing must be to BS EN 1149-5 [63]
- For footwear, must be to BS EN 61340 [64]
- For gloves, must be to BS EN 61340 [65].

For footwear and gloves, there is also a manufacturer recommendation on in-service electrostatic discharge testing at regular intervals.

7.1.2 Tools and Equipment

Equipment used in natural gas service shall not be assumed suitable for hydrogen service without review. The tools and equipment used by technicians will need to be reviewed to ensure they are suitable for use in hydrogen service. Experience from the LTS Futures live trial identified the following examples of tools and equipment requiring consideration (see Table 7.1).

Table 7.1 – Examples of Tools and Equipment Considerations for Hydrogen Service

Equipment item	Comment
Non-contact voltage detector	Existing voltage detectors used on the natural gas network not suitable for use with hydrogen and these were replaced with an ATEX IIC rated item and issued to all personnel.
GS700H	Existing gas surveyors could not detect hydrogen, and these were replaced with the GS700H with full range (PPM, %LEL and %vol) cells for both hydrogen and natural gas as well as an oxygen cell for purging operations. Both existing (GS700) and new (GS700H) are ATEX IIC rated.
Torches	Existing torches were replaced with ATEX IIC zone 0 compliant torches for those operating in the trial area.
Non-sparking hand tools	Non-sparking tool were provided at all sites to reduce the potential for ignition. It should be noted whilst these are not certified for use in hydrogen their use reduces the likelihood of ignition compared to standard tools.
Local/mobile digital pressure gauges	Additional mobile pressure gauges were supplied for each site. These were ATEX IIC rated.
Mobile phones	Acknowledging the remote and discrete locations between the sites and the need for active comms, ATEX IIC mobile phones were issued to personnel.
Personal Alarm Monitor	The Honeywell Microclip XL was identified as suitable for hydrogen use due to being IIC rated and alarm in a hydrogen atmosphere.

7.2 Integrity Management

The integrity management plan for high pressure natural gas transmission pipelines focuses on the threats from external corrosion and external damage. The integrity management plans for hydrogen will need to consider these threats as well as additional or degradation mechanisms associated with hydrogen service, including hydrogen embrittlement, accelerated fatigue, and increased erosion. Inspection methods, coverage and frequencies shall be appropriate to the materials, operating conditions and degradation mechanisms identified for hydrogen service.

The inspection regimes shall be capable of identifying degradation features relevant to hydrogen service, which include sharp or crack-like defects, localised stress concentrators, and surface or near-surface discontinuities, rather than solely volumetric metal loss typically associated with corrosion at likely locations for such features including welds.

The in-line inspection services providers are in the process of developing inspection tools that can operate in hydrogen and be able to detect and measure defects that may be affected by hydrogen. In the early stages of hydrogen operation, it may not be possible to control the flow in a pipeline to meet the speeds required for in-line inspection tools, so other techniques may need to be considered including coupons and other non-destructive techniques.

Given the limited hydrogen operational experience compared with natural gas, the frequency of inspections and surveys will be shorter to provide additional assurance. As confidence in the inspection methods improves, and the understanding of asset condition increases, inspection intervals may be reviewed and optimised.

A WSoE shall be developed and maintained by the Competent Person. Where existing inspection schemes were developed for natural gas service and primarily target corrosion or general wall loss, their continued applicability is not justified for hydrogen service and shall be revised accordingly. Any changes to inspection scope, techniques or frequency shall be documented and approved.

Inspection findings and review of technologies shall be reviewed to inform the ongoing suitability of inspection arrangements.

7.3 Live Connections (Hot Tapping and Stoppling)

The HSE guidance for "The safe isolation of plant and equipment" HSG253 currently states hot tapping and stoppling is "not appropriate for systems containing chlorine, oxygen, hydrogen, hydrogen sulphide or hydrogen fluoride".

When considering new connections under hydrogen service, it is reasonable to have a working assumption that good practice in natural gas provides a robust starting position than can be further developed, by reviewing and addressing the changes in risk which may result from hydrogen service.

It is important that the equipment is accepted as suitable for hydrogen service prior to operations. The adoption of enhanced Factory Acceptance Testing (FAT) and full operational demonstration style reviews could be implemented so both suppliers and operators understand the challenges when operating under hydrogen service. Such demonstrations, when conducted, could entail under both inert gas (Helinite) and 100 % hydrogen conditions as part of the operational acceptance process prior to live operations. These FATs can embed any additional requirements such as vent/purge requirements which could be required for hydrogen service. These steps are required to minimise the occurrence of potential explosive atmospheres when mounting and demounting equipment on the pipeline, especially once pipeline containment has been breached. There should be consideration of the operational impacts from the time taken to conduct additional testing.

The impact of potentially increased hazardous area zones must be considered as well as the potential for ignition at vent locations. This will necessitate change in design (from venting) and increased restricted areas (exclusion zones) while venting due to risk of ignition, and indirect purging should be considered and assessed for suitability.

A welded tee and grouted tee were applied and hot tapped during the LTS Futures live trial demonstrating two methods of making new connections. The STATS BISEP tool was successfully deployed and provided a demonstrated isolation capability in hydrogen. Both tees were plugged using a standard and lock-o-ring plus completion plugs. The LTS Futures live trial has demonstrated that it is possible to carry out these operations safely with appropriate adjustments to existing natural gas procedures.

It is recommended that there should be discussion with the HSE to review and update HSG253 to reflect the safe application of hop taps and stoppling on hydrogen pipelines. The gas industry should also develop a new standard for hot tap and stoppling operations on hydrogen pipelines, informed by the learning from the LTS Futures live trial. Consideration should also be given to the review and update of relevant specifications (e.g. */SP/P/9) for split tee welding and associated activities in hydrogen service.

7.4 Competence

A training and competency plan will need to be developed to consider all aspects of the pipeline lifecycle including the design, construction, operation and management of a hydrogen pipeline/installation. A systematic approach is required in reviewing the current competency framework, ensuring that all parties involved in operating a network have defined training and competency requirements for hydrogen. Such parties should include:

- Managers
- Technical staff
- Authorising Engineers/Competent Persons/Operators.
- Designers/Appraisers
- Contractors/Service providers
- Emergency Response Providers
- Training providers and assessors.

GDN's will need to review and where appropriate update the training they deliver to ensure personnel have the required skills to work with hydrogen. These skills will require regular assessment of continued competency and therefore a suite of CAS inspections will be needed. The Safe Control of Operations (SCO) and management procedures for working on near electrical equipment (EL/6) will also require updating to reflect additional training required for Authorising Engineers and Competent Person who will work with hydrogen.

For the LTS Futures project, it was recognised that the current training and competency framework could not be implemented to meet the needs of the trial. As the use of hydrogen is novel the shadowing process for training was not possible and therefore an alternative approach was taken to demonstrate that personnel were trained and competent to deliver the trial. The trial utilised existing personnel who were competent to carry out the respective operations/roles in natural gas and upskilled them to work with hydrogen. Training was delivered as a combination of theoretical and hands-on experience followed by both written and practical assessments. For operations which were new for the trial such as flaring, full training and assessment was carried out by the equipment provider.

7.4.1 Training

The LTS Futures project had a defined and limited set of operations to be completed and developed the following training to equip personnel to deliver the live trial operations. It should be noted that whilst some of these will apply across all networks (hydrogen awareness, emergency response), some were specific to the delivery of the trial such as entry unit operation and flaring procedures.

For the live trial, SGN developed specific training in the following areas:

- Project induction
- Site inductions
- Hydrogen awareness course (including PPE requirements)
- Potential Hydrogen Incident Consequences
  - Emergency Response Procedures:
  - Emergency response training for Hydrogen Pipeline Response Team (HPRT) including desktop scenarios and alarm response
  - Emergency response procedure briefing for FCO's, OCC and GCC
  - Guidance notes for Incident controllers
  - Guidance notes for Escalation
- Venting and purging operations
- Entry unit operations – Pressure control
- Entry unit operations – RTU, flame and leak detection (E&I)
- Gas sampling for odorant analysis
- Odorisation unit familiarisation
- GS700H training
- NRO briefings for all trial operations (purging, commissioning, hot works, flow stopping, flaring)
- Emergency exercises (internal SGN, INEOS, External with emergency services and local authorities)
- Flaring Procedures.

7.4.2 Competency Assurance Assessment

GDN's will need to review procedures/operations and develop Competency Assurance System (CAS) inspection criteria to ensure there is a consistent approach to reviews. The current natural gas approach of completing a period of shadowing someone following initial training is not possible for new hydrogen projects and therefore an assessment of competency needs to be completed to demonstrate capability to commission a project/start an operation. The frequency for inspections needs to be confirmed and within SGN this is carried out using critical task analysis to define high risk activities which require more frequent review. Competency criteria also need to be established for CAS inspectors. In future, when a hydrogen network and larger pool of personnel had been established this should be reviewed.

For LTS Futures, hydrogen specific assessments were carried out as part of the completion of training and due to the short duration of the trial, no further CAS inspections were carried out.

8 Future Considerations for GDNs

The following recommendations identify areas for further consideration by GDNs to support the repurposing of LTS assets for hydrogen service:

1. This LTS Futures Blueprint for Pipeline and Installation Repurposing for Hydrogen Service should be reviewed, and if required updated, following:
   a. Completion of the material and Pressure Reduction Installation (PRI) testing.
   b. Updates to the IGEM/TD/1 and IGEM/TD/13 Hydrogen Supplements and publication of the Fracture and Fatigue specification.
2. GDNs should engage with the HSE to determine how HSG253 can be updated to recognise that hot tap and stoppling operations can be safely undertaken on hydrogen pipelines.
3. GDNs should consider:
   a. Developing a standard for carrying out hot taps and stoppling on hydrogen pipelines.
   b. Updating */SP/P/9 for split tee welding for use with hydrogen pipelines.
4. GDNs should agree the criteria for girth welds of unknown quality for use in hydrogen service and consider developing a methodology and standard for their assessment.
5. GDNs should develop a standard for venting and flaring hydrogen from transmission pipelines and installations.
6. GDNs should consider developing a methodology and standard for assessing pipelines that may be affected by internal ISCC following operation in manufactured gas service.
7. GDNs should adopt the Asset Compatibility Tool and ensure that it is periodically reviewed and updated to reflect current knowledge on material suitability for hydrogen service.
8. GDNs should develop a standard for inspection, assessment and repair of damaged (not leaking) hydrogen pipelines operating at pressure great than 7 bar (i.e. a hydrogen version of GN/PM/P/11).
9. GDNs should develop an approach for emergency planning hazard distances for hydrogen pipelines.
10. GDNs should review and agree the approach to the recording and retention of asset information across the full pipeline lifecycle, including design, construction, operation, surveys, diversions and investigations, to support future hydrogen suitability assessments.

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Appendix A
Indicative Repurposing Cost Assessment

A.1 Introduction

This appendix provides an indicative assessment of the costs to repurpose the Local Transmission System (LTS) for hydrogen based on the work undertaken within the LTS Futures Project. As part of the LTS Futures Net Zero Pre Construction and Small Projects Re-opener (NZASP) submission to Ofgem, it was estimated that the repurposing of existing LTS pipelines and associated infrastructure will cost 15 – 30 % of the total cost to replace all these assets with new infrastructure. This Appendix to the LTS Futures Blueprint reviews the estimated cost of repurposing existing LTS pipelines using the costs incurred during delivery of the LTS Futures project. This assessment will be updated to include PRIs when test work in this area has been completed.

A.2 Assumptions

The following assumptions have been used to build the cost model, and these acknowledge that it does not act as a full cost breakdown of all aspects involved in repurposing and operating the LTS in a future transition scenario. The future supply and demand for hydrogen, including volumes, locations, and timing, has not yet been defined. Potential network configuration during and following a transition from natural gas to hydrogen is unknown and cannot currently be predicted with confidence. It is unclear whether the LTS would continue to serve a predominantly domestic demand profile, or if it would evolve to support a significantly higher proportion of industrial and commercial demand.

This cost assessment has excluded the following:

- Network capacity requirements, including transmission capability and the provision of diurnal storage.
- Changes to supply and demand profiles and their geographical distribution, which fundamentally influence the operation, balancing, and design of the LTS.
- Transition related costs or the mechanisms by which the transition from natural gas to hydrogen would be implemented, as these factors cannot currently be defined with sufficient certainty.
- Upgrade or implementation of Distribution Network Operator grid connection.
- Amendments to the Uniform Network Code (UNC) required to enable hydrogen operation, along with the costs associated with the transition process itself.
- Training required for future operation.
- Legal agreements e.g. network entry agreements, shipper agreements etc.
- Updates to Supervisory Control and Data Acquisition Systems (SCADA) e.g. for tracking of fatigue cycling.

In practice, transitioning from natural gas to hydrogen will require detailed, location specific transition strategies for each town and city. While it is expected that some parallel hydrogen infrastructure will be needed, the future steady state network configuration and site specific cut over plans must first be defined before reliable estimates of operational and asset costs can be developed. Once these future network parameters are better understood, the assessment can be refined.

Costs that are dependent upon the outcomes of specific pipeline and PRI repurposing assessments have been excluded from the assessment. These include:

- Required works to bring a pipeline into compliance with IGEM/TD/1 Edition 6. This is a requirement for the application of IGEM/TD/1 Edition 6 Supplement 2.
- Any additional material testing required where historical records are incomplete or unavailable.
- Negotiation and compensation associated with updating easements, servitudes or increased site outlay as required.
- Remediation measures identified through the repurposing assessments, such as repairs, diversions or equipment replacement (unless specified) or upgrade.

Whilst there are some exclusions from the cost model, the LTS Futures project is the first UK project to repurpose an existing natural gas pipeline and block valve to hydrogen. It is also the first project to construct a new pipeline and entry unit in accordance with IGEM/TD/1 Edition 6 Supplement 2.

A.3 Pipeline Cost Model

The pipeline cost model has been split into two sections – "one-off" and "per-pipeline" costs, see Figure A.1 - Indicative Repurposing Cost Model for Pipelines.

A.3.1 One off cost element

The one-off cost elements were divided into three categories:

- **Policies, procedures and standards** relate to future considerations identified in the LTS Futures Blueprint. These include development of revised hydrogen standards and procedures, development of criteria for assessment of welds of unknown quality, and development of a methodology for assessing the potential for Internal Stress Corrosion Cracking (ISCC). These activities are recommended to build confidence in long term hydrogen operation but are not pipeline specific.
- **Pipeline material hydrogen testing** is an activity that would be undertaken only until a sufficient evidence base has been established. It is assumed to be required for the first 20 pipelines to be repurposed, after which additional pipelines may rely on the established evidence base.
- **Safety case development** would be required for any pipeline repurposed to hydrogen. The magnitude of the work involved would likely be dependent on the way the network is transitioned e.g. isolated distinct hydrogen sections or full transition.

A.3.2 Per pipeline cost element

The cost elements applicable to each pipeline are grouped into six distinct categories:

- **Technical Assessments** - These assessments consider the specific characteristics and condition of the pipeline and collectively inform the pipeline repurposing report. They include the engineering evaluations necessary to demonstrate suitability for hydrogen operation.
- **Records Collection** - Activities required to gather, review, and validate historical pipeline data to support the repurposing assessment.
- **Quantitative Risk Assessment (QRA)** - Generation or modification of new or existing pipeline QRA. Ensures up to date population density in pipeline corridor.
- **Support Activities** - Ancillary activities required to enable completion of the repurposing report and to update records and asset management systems once a pipeline has been repurposed for hydrogen service.
- **Site Works** - Physical works undertaken on the pipeline, including the installation of marker posts and weld recovery for material testing.

A.3.3 Cost Model Scenarios

A low, medium and high-cost scenario for each element has been developed and are shown in Table A.1 with outline criteria for each level. Whilst it is not possible to cover every variation, the scenarios should provide the user with guidance. Each pipeline will have a unique scenario depending on its current status and the level of work required to repurpose the pipeline to hydrogen.

Figure A.1 – Indicative Repurposing Cost Model for Pipelines

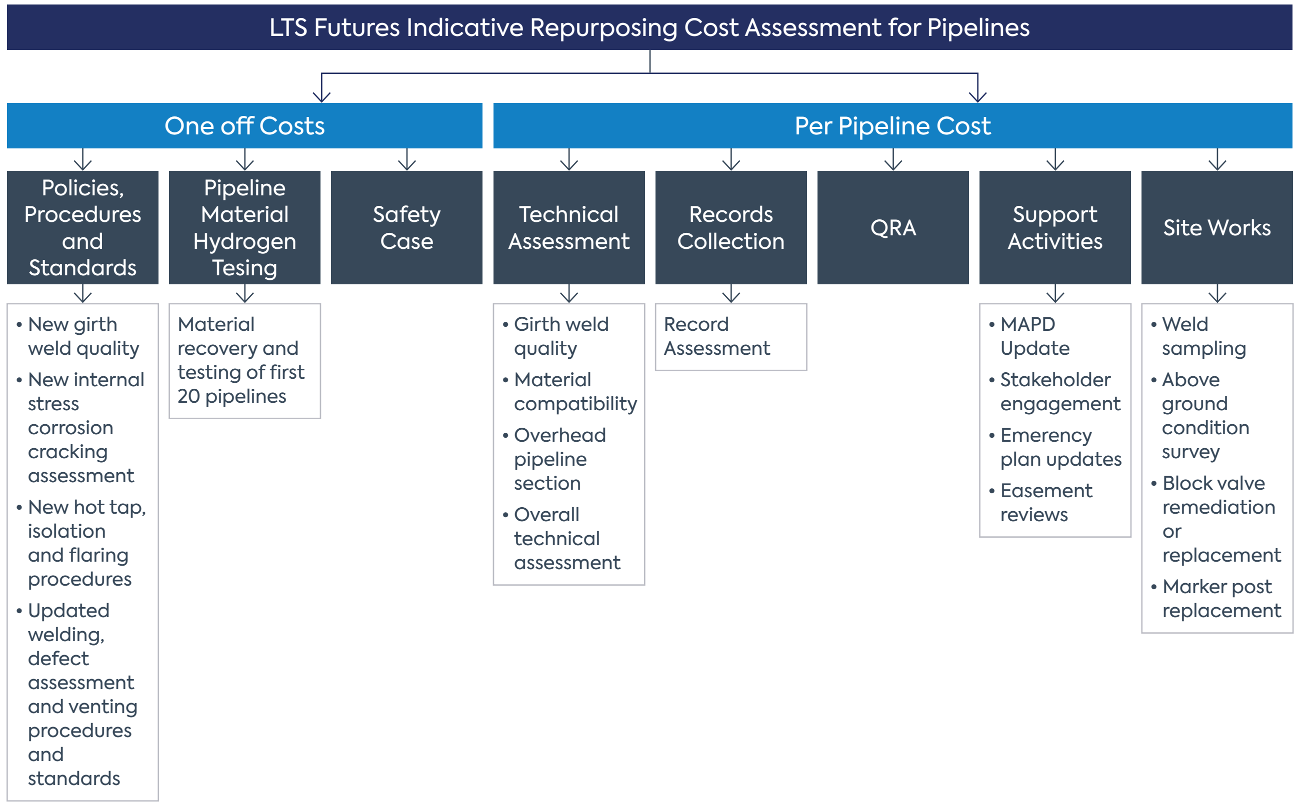

Table A.1 – Indicative Repurposing Cost Model for Pipelines per pipeline costs

Cost Element	Description	Low	Medium	High
Records assessment	Retrieval of records from archives.	Good quality TD1 affirmation reports All records aligned with GIS system No diversions Minimum 2 people for 1 month + 2 people for 2 weeks for each 5 km of pipeline Eg for a 20 km pipeline this would equate to 2 people for 3 months (960 hours).	TD1 affirmation reports are available. Partial records aligned with GIS system Diversion on the pipeline with fragmented records Minimum 3 people for 2 months + 3 people for 3 weeks for each 5 km of pipeline Eg for a 20 km pipeline this would equate to 3 people for 5 months (2400 hours).	Limited data in affirmation reports. Records not aligned with GIS system Missing records/ references Multiple diversions – fragmented records. Minimum 5 people for 3 months + 3 people for 4 weeks for each 5 km of pipeline Eg for a 20 km pipeline this would equate to 8 people for 3 months and 3 people for 1 month (4320 hours).
Weld Quality Assessment	Requirement depends on year of construction. Pre-1972 pipelines will require this.	Post-1972 pipelines only.	Pre-1972 pipeline with some records e.g. diversion with girth weld checks or records from previous investigations.	Pre-1972, no records of weld quality either at or post construction or existing known issues.
Weld sampling/ assessment	To include excavation at location, NDT, sampling and technical review of assessment.	Not required.	Minimum 3 welds to be investigated with a frequency of 1 per 5 km of pipeline NB: this can be reviewed as the sampling assessment is completed potentially reducing the total number required.	Minimum 3 welds to be investigated with a frequency of 1 per 1 km of pipeline NB: this can be reviewed as the sampling assessment is completed potentially reducing the total number required.
QRA	Cost dependent on population density and number of site-specific assessments required.	No previous QRA as pipeline has no infringements in relation to IGEM/TD/1 Ed 6 or a previous QRA and there is no/ minimal change to population profile. In these cases, a screening assessment should be performed and the highest population area assessed with the hydrogen methodology as a proxy for the whole route.	Existing QRA with significant changes to population density along the route. Screening assessment completed and QRA updated to reflect population updates and hydrogen methodology.	No existing QRA and high population density along the pipeline route. Screening assessment identifies multiple site specific QRAs are required to be completed with the hydrogen methodology.
Material Compatibility assessment	Technical assessment of existing repairs and/or pipeline fittings e.g. new connections, stopple fittings, Insulation Joints etc. to consider their compatibility and suitability for hydrogen service.	No repairs or new connections exist on pipeline.	1 – 5 repairs or new connections completed on pipeline.	> 5 repairs or new connections completed on pipeline.

Single block isolation replacement with DBB	Single block isolation valves may require replacement with DBB.	No removal and replacement.	Excavation, remediation work on valve and reinstatement.	Removal and replacement of single isolation block valve with new DBB.
Above Ground Condition Survey	Preparation work for and completion of above ground surveys including e.g. depth of cover, CIPS, DCVG, river crossing checks.	Pipeline corridor is well maintained, and surveys are carried out to update records.	Pipeline corridor requires some preparation for completion of above ground surveys (e.g. depth of cover, CIPS, DCVG).	Pipeline corridor requires significant preparation for completion of above ground surveys (e.g. Depth of Cover, CIPS, DCVG, river crossing checks).
Overhead Pipeline Section Crossing	Consider if replacement is required for hydrogen service.	No overhead pipeline crossings present on the route.	Overhead pipeline crossing(s) present on route. Structural survey, condition assessment, assessment of protection measures and site specific QRA required.	Overhead pipeline crossing(s) present on route. Structural survey, condition assessment, assessment of protection measures and site specific QRA required.
Marker post re-signing	Marker post remediation or relabelling to ensure pipeline route is identifiable.	Mark posts are well maintained, and minimal remediation is required. 20 % replacement or new signage. (Replacing 1 post every 1km)	Marker posts require remediation and update to labelling. 50 % replacement and new signage. (Replacing 2.5 posts per km)	Marker posts are in poor condition or missing and require full replacement. 100 % replacement and new signage. (Replacing 5 posts per km)
Internal and Local Authority (LA) Emergency plan review and update	Producing an appendix to inform LA emergency plans and engagement with LAs.	LA has existing knowledge of hydrogen. The appendix for emergency plans is submitted for review and integrated by the LA to their plans.	LA has no existing knowledge of hydrogen. An appendix to emergency plans is produced and detailed engagement with LA is required regarding integration of this.	There is multiple LAs to engage with across the pipeline route who have no existing knowledge of hydrogen. An appendix to emergency plans is produced and detailed engagement with multiple LAs and emergency services is required for integration.

Detailed Technical assessment	Overall assessment of materials, fittings, defects, fatigue, and operating conditions. Desktop review of complied records is required by a technical expert	No known pipeline defects to be assess, no fatigue loading and up to date, reliable primary records available for review.	Either defects to be assessed or fatigue assessment required. Reliable primary records available for review.	Multiple defects to be assessed and full fatigue assessment required. Records review requiring judgement of secondary and tertiary information sources.
Stakeholder engagement	Engagement with Landowners, tenants, businesses, safety regulator, environmental regulator, local authority planning.	Single landowner/ tenant, limited number of businesses, single planning authority.	Less than five landowners/tenants, businesses and planning authorities.	Multiple (e.g. more than five) landowners, tenants, multiple businesses, multiple local authorities.
MAPD	Update to existing MAPD document to reflect change of use and HSE notifications.	This is expected to a fixed cost per pipeline and therefore profiling has not been included.		
Records update	Update to internal systems e.g. Synergi, Geofield, LSBUD, Maximo PSDB.	Assumes that current records are up to date and there are no additional dig records to be added 1 person for 2 weeks.	Update of records is required and there are minimal dig verification records to be added (<=3) 1 person for 1 month.	Multiple (>3) modifications, dig verifications, sampling carried out which require detailed records to be created 1 person for 2 months.

A.4 Model methodology

A.4.1 Cost model example

Below is a worked example application of the indicative repurposing cost assessment for a SGN pipeline displayed in Figure A.2 – Farningham to Hadlow Pipeline Route listing the assumptions that have been made to apply a high, medium or low indicative cost to each element. It should be noted that whilst the pipeline selected is a real asset, assumptions have been made on some elements, and this example is a demonstration of the use of the model only.

Table A. 3 provides an indicative cost assessment for repurposing the Farningham to Hadlow pipeline. In addition to these pipeline specific costs the below one-off costs would be included:

- Safety Case – £540,000
- Material Assessment – £155,000
- Development of hot tap, isolation and flaring procedures for hydrogen – £591,360
- Update to */P/9 (live welding), */P/11 (defect assessment) and IGE/SR/23/HAZ/2 for hydrogen – £443,520.

Costs for development and update to policies and procedures are not unique to this pipeline so may be spread across multiple repurposing projects. Although identified as one-off costs in the indicative repurposing model, costs for development of a methodologies and standards for assessing pipelines that may be affected by internal Stress Corrosion Cracking (ISCC) and unknown girth weld quality would not be required for this pipeline due to its year of construction.

Figure A.2 – Farningham to Hadlow Pipeline Route

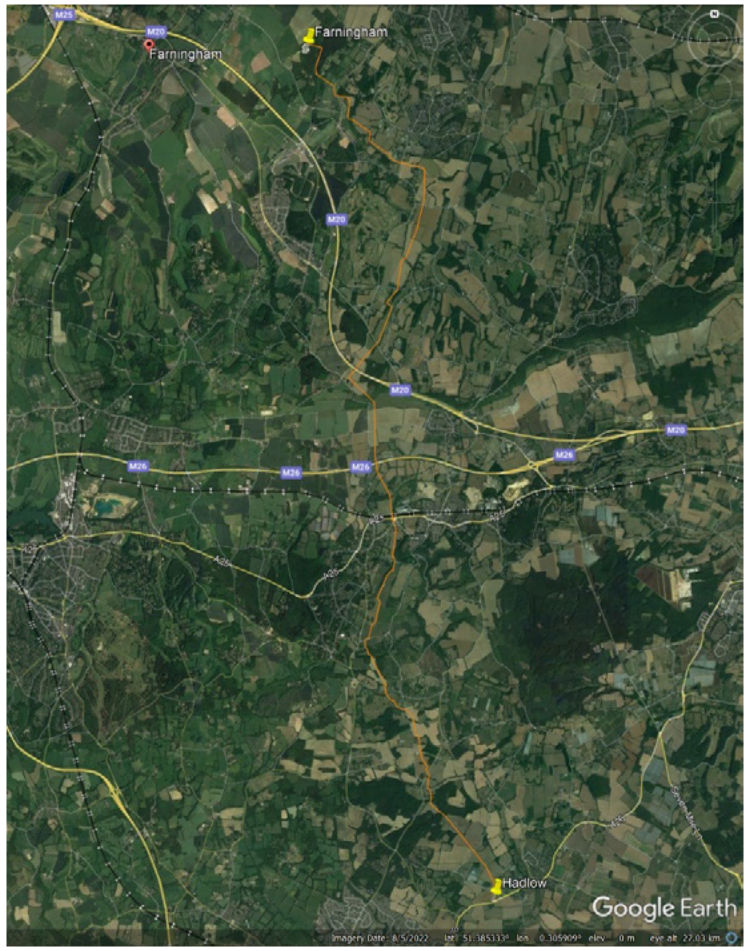

Table A.2 – Pipeline parameters

Parameter	Value
Pipeline Name	Farningham to Hadlow
Construction Date	2009
Design and Original Operating Code	IGE/TD/1 Edition 4
Repurposed Operating Code	IGEM/TD/1 Edition 6 and Supplement 2
Product	Natural Gas
Pipeline Length	22 km
Pipeline Diameter	1219.2 mm
Pipeline Wall Thickness	19.1 mm
Hydrotest Pressure	112 to 154 barg
Design Pressure	66 barg
Current MOP	38 barg
Design Factor	0.28
Nominal Depth of Cover	1.1 m
Fittings – Flanges etc.	Class 600

Table A.3 – Cost assessment example for repurposing of the Farningham to Hadlow pipeline

Cost Element	Cost (£) High	Cost (£) Med	Cost (£) Low	Description
Records assessment	–	–	£76,800	Good quality TD/1 reports are available and there have been no diversions or modifications since construction.
Weld Quality Assessment	–	–	£3,200	Post 1972 construction review of records is required.
Weld sampling/ assessment	–	–	£0	Post 1972 construction therefore not required.
QRA	–	–	£35,000	There for no habitable building proximity infringements.
Block Valve	–	–	£0	No block valve noted.
Compatibility assessment	–	–	£0	The pipeline has not had any modifications or diversions since construction.

Above ground condition surveys	–	£41,760	–	1.841 km of overgrown easement to be cleared to facilitate inspections.
Overhead pipeline section	–	–	£0	There are no overhead pipeline sections on the route.
Marker post replacement	£44,300	–	–	From TD/1 MOP affirmation reports – 69 missing or damaged marker posts require replacement and consideration of the installation of an addition 58 aerial marker posts
Emergency plan assessments and updates	–	£62,200	–	Assumed to be a single LA with no existing hydrogen knowledge.
Technical assessment	£92,400	–	–	Current design factor (0.35) satisfies requirements on IGEM/TD/1 Edition 6 Supplement 2. Material testing required as no SGN data for X65/2009/SAW pipeline material or B/12 and F/1 fittings material. or B/12 and F/1 fittings material. Known defects on pipeline. Fatigue assessment required (assuming current natural gas operational cycles). No significant external loading on pipeline. No obvious modifications identified.
Easement, Wayleaves and servitudes	–	–	£8,860	Legal review has informed that existing servitudes are suitable for use with hydrogen and pipeline in relatively new and records assumed to be up to date.
Stakeholder engagement	£13,920	–	–	Unknown number of landowners/tenants/businesses therefore assumed to be high Rail and motorway crossing identified which will require engagement with Network Rail.
MAPD	–	£4,640	–	Fixed cost for a pipeline
Records update	–	–	£9,280	Constructed in 2009 with no weld sampling require records update assumes to be minor.
Total	**£392,360**			

A.5 LTS Futures Specific Cost Comparisons

The following sections compare the actual costs incurred by the project with the potential costs associated with completing these operations when repurposing the LTS network. This includes:

- Repurposing 30 km of existing LTS pipeline
- Design, procurement and construction of an 80 NB hydrogen supply pipeline
- Design, procurement and construction of a hydrogen entry unit
- Design, procurement and construction for Newton block valve (including block valve repurposing).

A.5.1 Repurposing 30 km of Existing LTS Pipeline

As part of the LTS Futures Live Trial, the 450 NB Grangemouth to Granton pipeline was repurposed to hydrogen providing an insight to actual costs associated with this process. This pipeline is broadly representative of the wider LTS network; however, it had been kept under nitrogen preservation for several years. As a result, a detailed assessment of its condition was required prior to repurposing.

The total costs incurred when repurposing the 450 NB pipeline can be separated into two distinct categories:

Costs specific to the Live Trial

- These costs were specific to the Live Trial. These activities included:
  - Full pipeline hydrostatic test
  - 50 metre cut-out and replacement for materials testing
  - Swabbing/gauge plate pigging runs
  - Case for Safety updates to account for hydrogen-specific hazards and controls
- LTS pipelines that will be repurposed in the future are likely to have remained operational and are subject to the IGEM/TD/1 Edition 6 four-yearly MOP affirmation requirements and therefore will not require hydrostatic testing and pigging
- The total cost incurred for only these activities was: £878,049.

Costs associated with preparing the pipeline for hydrogen service

- This category includes the costs directly attributable to repurposing the pipeline for hydrogen service. These costs are considered representative and applicable to future LTS hydrogen repurposing projects. Examples include:
  - Material testing to demonstrate compatibility with hydrogen, in line with IGEM/TD/1 Edition 6 Supplement 2
  - Above ground surveys and subsequent dig verifications
  - QRA to understand changes to the risk profile under hydrogen operation.
  - MAPD, emergency plan appendix and local authority update
  - Legal review of servitudes, easements and wayleaves
  - Stakeholder engagement with landowners/tenants, emergency services and local authorities to notify and update them on the introduction of a hydrogen to a pipeline within their area
  - The total cost incurred for only these activities was: £885,223.

Repurposing the 30 km, 450 NB Grangemouth to Granton pipeline for hydrogen incurred total costs of £1,638,272. Based on a pipeline length of approximately 30 km, this equates to a hydrogen repurposing cost of £54,609 per km specific to the LTS Futures Live Trial and £29,507 per km for future repurposing projects.

A.5.2 Design, Procurement and Construction of an 80 NB Hydrogen Pipeline

As part of the LTS Futures project, a new 1.2 km hydrogen transmission pipeline was constructed in accordance with IGEM/TD/1 Edition 6 Supplement 2.

The pipeline was constructed within a dense industrial cluster which is potentially representative of the environment in which new hydrogen transmission tie-ins will connect the LTS network to supply/demand centres. The pipeline was 80 NB, grade L245NE with a wall thickness of 5.5 mm.

Construction included several challenging aspects, including an overhead river crossing (bridge), navigating a congested culvert, and installation via horizontal directional drilling (HDD) into a top tier COMAH site. In addition, the project required the development and qualification of hydrogen specific welding procedures, representing a first of a kind activity. These development costs are expected to reduce over time as hydrogen welding procedures are standardised and reused across future hydrogen pipeline construction projects.

- **Costs associated with Live Trial requirements:**
  - These costs include design and construction costs associated with tie-in pipework within the hydrogen suppliers site, non-competitive tender of works complete by incumbent contractors on the supply facility site, additional technical assurance for specialised activities such as HDD and significant technical support from a specialised welding contractor for project specific welding≈procedures.
  - The total cost incurred for only these activities was: £1,313,009.

- **Costs associated with new hydrogen pipeline**
  - These costs include the design of the pipeline (including approval and appraisal), associated environmental surveys and consents, planning applications, main contractor (fabrication and installation including HDD), pipeline material, isolation valves, insulation joints, 3rd party inspection, instrumentation including flame and leak detection and QRA for the pipeline route.
  - The total cost incurred for only these activities was: £4,536,000 equating to an average cost of approximately £3.78 million per km.

A.5.3 Repurposing Newton Block Valve

The Newton Block Valve site required significant work to design and install equipment used to facilitate the LTS Future Live Trial. The existing block valve was repurposed, and the overall site footprint did not require extension. The total costs incurred when repurposing the Newton Block Valve can be separated into three distinct categories:

- **Costs associated with repurposing the site for the Live Trial**
  - These costs have been excluded from further assessments and included the design (including approval and appraisal), procurement and construction of a 150 NB bypass around the Newton Block Valve incorporating isolation, telemetry, sampling and pressure control. The site also included a temporary flaring equipment as well as increased data monitoring and capture capability. This equipment would not be relevant to repurposing an existing block valve installation for hydrogen.
  - The total cost incurred for only these activities was: £816,949.

- **Costs associated with repurposing the site for hydrogen service**
  - These costs included remediation work on the block valve including excavation and reinstatement, overhaul of the valve vent and sealant line, valve greasing, coating inspection/renewal and concrete support inspection. Costs for design, procurement, installation and testing of flame and leak detection have been included as well as review of site layout and update of hazardous area drawings.
  - The total cost incurred for these activities was: £445,408.

- **Costs associated with block valve replacement for hydrogen service**
  - The project did not replace a block valve but did complete several activities and obtained costs that would be required for this activity. Costs have been included and estimated based on the below:
  - Design – A full design process would be required including approval and appraisal for replacement of a block valve encompassing civil, mechanical and potentially electrical works (earthing) in accordance with */PM/PS/5 and *WI/PS/6. The design works completed for the Newton site were similar in scale to those that would be required for block valve replacement.
  - Excavation – A full excavation of the block valve was completed for inspection and valve overhaul. The excavation was a similar size to that which would be required for valve cut-out and replacement.
  - Welding costs – The project qualified and completed production circumferential welds onto the 450 NB pipeline. IDN/PM/Q/10, weld procedure qualification, pipe preparation, pre- and post- work NDT, welding, competent third-party supervision and inspection were required with similar costs for block replacement needed.
  - Lifting operations – Movement of the cut-out and replacement valve would be required. Several similar lifting operations were completed during the Live Trial.
  - Valves and associated vent lines etc. – The project has obtained costs for a CL600 450 NB isolation valve with vent and drain lines. Two valves would be required for DBB isolation.
  - Costs for procurement, installation and testing of fire and gas detection have been included. It is assumed that a live operation (e.g. hot tap and isolation) is not used as the method of replacement and work is completed offline.
  - The total cost projected for these activities is: £580,544.

A.5.4 Building a New Hydrogen Entry Unit

As part of the LTS Futures Live Trial, a new hydrogen Pressure Reducing Installation was designed, fabricated, tested and installed in accordance with IGEM/TD/13 Edition 3 Supplement 1. As the Live Trial did not supply customers, security of supply was not critical, and therefore a single stream entry unit was installed. It is acknowledged that a twin stream entry unit would be required for a new hydrogen ready PRI installed on the LTS to ensure that supply could be maintained and essential maintenance carried out. The costs associated with building a new hydrogen PRI can be split into two distinct categories:

- **Costs associated with Live Trial requirements:**
  - These costs have been included procurement and installation of a new odorization unit and testing offsite testing of the entry unit prior to installation for the Live Trial. Testing included a hydrotest, helium/nitrogen leak test and full suite of functional checks. It is expected that functional testing would be completed by a skid manufacturer in the future.
  - The total cost incurred for only these activities was: £302,014.

- **Costs associated with new hydrogen entry unit build**
  - These costs include a full design process including approval and appraisal, encompassing civil, mechanical, electrical, instrumentation and software elements in accordance with */PM/PS/5 and *WI/PS/6. The PRI included isolation, pressure/flow control, metering, instrumentation, telemetry, safety devices. No gas analysis was included in the entry unit design as the INEOS supply facility had an existing gas analyser that provided data periodically.
  - Civil works included installation of concrete pads, pipe supports, cable ducts, new fencing and excavations to connect to below ground pipework and burial of earth mats. Mechanical works included offsite fabrication of the entry unit and on-site assembly. Electrical and instrumentation works included procurement, install and testing of site earthing, power and communication cables, new control kiosks, flame and leak detection, telemetry, remote telemetry unit and associated electrical distribution and safety devices. Leak testing was completed using a helium/nitrogen gas mix to ensure no fugitive emissions. The PRI was also coated in accordance with GIS/PA/10.
  - The total cost incurred for only these activities was: £2,041,568.
  - The projected cost for a twin-stream system (assuming only additional costs are second stream components including control valves, safety devices, isolation valves and telemetry) is: £2,366,587.

A.5.5 Cost Comparison Between LTS Futures Reality and Bid

Pipelines

Within the LTS Futures bid, the cost of constructing a new LTS pipeline network was estimated for comparison purposes. The estimated cost of building a new 11,000 km LTS network is £11.889 billion, equating to an average construction cost of £1.081 million per km. These costs are comprised of approximately 65 % main contractor costs, 21 % materials, and 14 % resource costs.

Since the submission of the LTS Futures bid in 2021, the external cost environment has materially changed. Increased geopolitical volatility has heightened focus on energy security and has contributed to sustained inflationary pressures across the UK economy. There have been significant increases in construction, labour, and materials costs, which directly impact both new build and repurposing pipeline cost assumptions. As a result, cost estimates developed at the time of the original bid are no longer fully reflective of the current market environment, consistent with trends observed across Ofgem regulated infrastructure projects.

Using ONS Consumer Prices Index (CPI) data:

- 2021 annual CPI index: 111.6
- 2025 annual CPI index: 138.4
- Cumulative inflation (2021–2025): ~24.0 % [66].

Applying this inflation uplift to the original estimate:

£1.081 million per km × 1.24 = ~£1.341 million per km (in 2025 prices)

The LTS Futures 80 NB pipeline construction consisted of the breakdown listed in Table A. 4. The total cost of construction was £4.536 million excluding trial specific costs.

Table A.4 - LTS Futures Bid and 80 NB Pipeline Construction Breakdown

Costs	LTS Futures Bid (%)	LTS Futures 80 NB Pipeline (%)
Main Contractor	65	78
Material	21	14
Resource	14	8

The main contractor costs for construction of the 80 NB pipeline are a higher percentage than those projected in the LTS Futures bid. This is likely due to the relatively low cost of materials given the small diameter of the pipeline.

Based on the inflation adjusted new build cost estimate and the observed costs from the 80 NB hydrogen pipeline delivered under LTS Futures it is estimated that new hydrogen pipeline construction costs are likely to fall within a range of approximately £1.34 million per km to £3.78 million per km, depending on route complexity, diameter, and site specific constraints.

A.5.6 Summary

Table A.5 provides a summary of cost data collected during the LTS Futures trial.

Table A.5 - Summary of costs incurred during LTS Futures and estimated future costs

Costs	80 NB hydrogen pipeline	Repurposing of Existing Pipeline (per km)*	Block Valve Repurposing	Hydrogen Entry Unit**
Incurred by LTS Futures	£5,849,000 (£4.87 million/km)	£54,609 per km	£1,025,952	£2,668,601

*Assuming a pipeline of similar size, material, condition. **Cost projection for twin stream PRI.

Based on the inflation adjusted LTS Futures new build cost estimate and the observed costs from the 80 NB hydrogen pipeline delivered under LTS Futures, it is therefore estimate that new hydrogen pipeline construction costs are likely to fall within a range of approximately £1.34 million per km to £3.78 million per km, depending on route complexity, diameter, and site specific constraints.

Using evidence from the 450 NB repurposing project and the wider GDN cost model, repurposing existing LTS pipelines for hydrogen is estimated to cost in the range of £20,500 per km to £129,500 per km, which is materially lower than the estimated new build costs (1.5 – 9.7 % of new build excluding decommissioning costs).

It should be noted that there is significant variation in cost to repurpose depending on the available information on weld quality. Pipelines of unknown girth weld quality are likely to have high costs for elements which are excluded from this cost assessment due such as diversions, repairs etc.

In addition, costs that are dependent upon the outcomes of specific pipeline repurposing assessments have been excluded at present which are likely to be significant. These include:

- Required works to bring a pipeline into compliance with IGEM/TD/1 Edition 6. This is a requirement for the application of IGEM/TD/1 Edition 6 Supplement 2.
- Any additional material testing required where historical records are incomplete or unavailable.
- Negotiation and compensation associated with updating easements, servitudes or increased site outlay as required.
- Remediation measures identified through the repurposing assessments, such as repairs, diversions or equipment replacement (unless specified) or upgrade.

In addition to the cost advantages, repurposing existing LTS pipelines for hydrogen offers several benefits compared to new build construction:

- **Environmental and carbon benefits**
  - Repurposing avoids the need for new steel pipe manufacture, which is a highly carbon intensive process. Steel production represents a significant proportion of embodied carbon in new pipeline construction.
  - Re use of existing assets materially reduces whole life carbon emissions when compared with the extraction, manufacture, transport, and installation of new pipeline materials.
  - Reduced construction activity results in lower carbon emissions associated with construction plant, workforce travel, and material deliveries.
- **Reduced construction and supply chain impacts**
  - Significantly fewer construction activities are required relative to new build pipelines, reducing reliance on constrained construction and materials supply chains.
  - Lower requirements for heavy plant, materials handling, and logistics reduce exposure to construction market volatility and supply disruption.
- **Reduced public and community disruption**
  - Repurposing minimises the scale and duration of excavation works, resulting in less disruption to local communities, road users, landowners, and businesses.
  - Shorter construction periods and reduced surface works lead to lower impacts on traffic, noise, and access.
  - Reduced interaction with environmentally sensitive areas and third party assets compared with new pipeline routes.
- **Planning and consenting benefits**
  - Use of existing pipeline corridors reduces the need for new land take and simplifies planning and stakeholder engagement.
  - Lower risk associated with third party crossings and novel routing challenges typically encountered with new build infrastructure.

Appendix B
Differences between Hydrogen and Natural Gas

Characteristic	Unit	Hydrogen	Natural Gas (Methane)	Comment
Gross Calorific Value	MJ/m³	12.1	37.78	Approximately three times the volume of hydrogen required to deliver similar energy to natural gas.
Net Calorific Value	MJ/m³	10.22	34.01	
Flammability Range LFL - UFL	Vol %	4 – 75.6	5 – 15	Significantly larger flammable range.
Stoichiometric fuel % in air	Vol %	29.5	9.5	Increased probability of ignition (ignition from static discharge). The minimum energy for ignition of natural gas is 0.26 mJ and hydrogen 0.01 mJ at stoichiometric concentrations. However, at lower flammable limit the energy required for ignition is similar to that of natural gas.
Limiting oxygen % combustion	Vol %	5	12	Volume of oxygen required to support combustion is less than half that required for natural gas.
Minimum spark ignition energy	mJ	0.02	0.29	Energy required for ignition of hydrogen is ten times less than that required for natural gas at stoichiometric.
Maximum laminar burning velocity	m/s	3.1	0.4	Increased flame speed, potential for higher explosion overpressures, than natural gas where the thermal radiation distances are the dominant effect.
Density	Kg/Sm³	0.0853	0.6785	Hydrogen is significantly lighter (less dense) and subsequently more buoyant than natural gas. Any release of hydrogen is likely to rise quickly.
Flame visibility		Poor visibility in daylight	Blue/yellow flame	This is particularly an issue where a leak is from above ground pipework. For below ground releases, entrained dust/debris will make the flame visible.
Molecular weight	mol/g	2.016	16.042	Greater chance of leakage because hydrogen is a smaller than natural gas.
ATEX Rating	-	Group IIC	Group IIA	IIB + rated equipment may also be used with hydrogen.

Appendix C
Asset Compatibility Tool

The Asset Compatibility Tool (ACT) method allows the assessment of the suitability of existing LTS assets operating in natural gas service for conversion to hydrogen service at pressures above 7 barg up to 94 barg. It has been implemented as an Excel tool [67] with an associated user guide [68]. Note that assessments performed using the ACT method should be carried out by an expert team, as described in the user guide.

The ACT method defines an asset as an assembly that operates as a whole to perform an overall function within the network, such as transmitting gas, regulating flow, or providing emergency response. An asset assembly may comprise multiple components of different materials, or a single component of a single material.

The ACT method can be summarised as:

1. Identification of individual components that make up the asset assembly.
2. Identification of the material of each component.
3. Evaluation of the asset assembly to determine a natural gas risk score.
4. Evaluation of each component for suitability in hydrogen service to determine a hydrogen risk score.
5. Combination of the natural gas and hydrogen risk scores and comparison with a defined threshold score to determine an initial pass or fail.
6. Reassessment of components with an initial fail following application of mitigation options, which may enable a component to pass.

The natural gas risk score is assessed using a defined set of criteria that capture how well the asset is understood, how it operates, and the context in which it is installed. These criteria are combined to produce an overall natural gas score that represents the relative risk of the asset in natural gas service.

The hydrogen risk score is assessed using criteria that reflect material degradation in hydrogen, loading conditions, and the consequence of failure, and are combined to produce an overall score representing the relative risk of the component in hydrogen service.

The threshold value is intended to support engineering judgement and should not be applied automatically. Borderline scores close to the threshold should prompt further review of assumptions, data quality, and sensitivity to reasonable variations before acceptability is confirmed.

Good practice requires the method to be applied using the supporting guidance [69], by a suitably competent assessment team, with transparent recording of inputs and assumptions, and with additional checks or sensitivity studies undertaken where results are close to threshold values.

Consideration should be given to the consistent application of the ACT method and to the development of a library of completed assessments to support learning and comparability. Material degradation scoring should be revisited where appropriate as further relevant research becomes available.

If the fittings from the original pipeline and/or modifications/diversions cannot be classified as acceptable for hydrogen service using the ACT method then material qualification in accordance with IGEM/TD/1 Supplement 2 should be completed to assess the acceptability for hydrogen service.

Appendix D
Manufactured Gas Service and ISCC

Manufactured gas service shall be assessed to determine whether the pipeline may be susceptible to internal stress corrosion cracking (ISCC). Manufactured gas historically transported by the LTS prior to conversion contained carbon dioxide, water and carbon monoxide (CO). CO forms a thin protective film on steel surfaces which inhibits general corrosion; however, when this protective layer is locally disrupted, the exposed steel can corrode preferentially, forming notches that may develop into colonies of circumferentially oriented internal stress corrosion cracking.

Water, carbon dioxide, and CO are necessary for cracking to occur while other gas constituents influence the cracking rate but are not necessary for cracks to form.

Higher CO partial pressure increases the degree of corrosion inhibition resulting in an increase in the potential between the inhibited and uninhibited surfaces. Any exposed metal will experience the full corrosion rate and the adjacent steel with the passive film will dissolve at a reduced rate controlled by the CO partial pressure. The concentration of the corrosion process to a small area accelerates the growth of the notch.

Higher CO partial pressure reduces the stress needed to instigate ISCC and increases the crack growth rate. Higher stress means increased crack driving force resulting in an increased crack growth rate.

Internal coatings do not cover girth welds, and these areas are the most susceptible to ISCC.

Exposure to Manufactured Gas

Prior to conversion to natural gas, manufactured gas varied in composition depending on the gas plant, process employed and feedstock.

Coal was the primary feedstock for manufactured gas production until the 1960s. Rising coal costs, together with the increasing availability of oil and other hydrocarbons, drove the development and adoption of alternative gas manufacturing processes.

Oil based gas manufacturing proved more cost effective than newer coal-based processes, such as the Lurgi gasification plants constructed at Coleshill and Westfield. With the exception of these installations, gas manufacturing plants commissioned during the 1960s predominantly utilised hydrocarbon feedstocks.

These later plants produced gas at significantly higher pressures, enabling longer distance transmission and facilitating the development of Super Grids, local transmission systems operating at pressures of up to 300 lbf/in^2 (20.7 bar).

A parallel development during the 1960s was the importation of liquefied natural gas (LNG), primarily from Algeria, alongside the discovery and development of natural gas resources in the North Sea. The National Methane Pipeline was constructed in 1962–1963 to distribute regasified LNG from the Canvey Island terminal. This pipeline formed the precursor to the later 'Feeder' pipelines that became part of the National Transmission System (NTS), transporting North Sea gas to the twelve area boards at pressures of up to 1,000 lbf/in^2 (69 barg) [70].

Different gas manufacturing processes produced gases with differing CO partial pressures, with coal based manufactured gas generally containing higher CO levels. CO is poisonous [71], and in 1962 the Gas Council introduced a recommendation that new gas plants limit CO content to less than 2 % [72]. CO conversion processes were applied to most plants commissioned after 1962 and were frequently retrofitted to existing installations.

In general, the reduction in CO content had the effect of reducing the risk of ISCC. However, the effect of operating pressure on CO partial pressure remains a relevant consideration when assessing historical service conditions.

Conversion

Natural gas has a higher energy density and is safer than manufactured gas, with a reduced risk of CO poisoning. It was announced that the conversion from manufactured gas to natural gas would commence after a successful scheme to convert Canvey Island. The conversion process started in 1967 and took 10 years to complete with Scotland being the last Local Distribution Zone (LDZ) to be converted. Table D.1 shows the completion dates of conversion for the 12 Local Distribution Zones.

Table D.1 - Conversion Completion Dates by Local Distribution Zone [73]

Region	LDZ	Completion Month	Completion Year
Scotland	SC	September	1977
Northern	NO	July	1975
Northwest	NW	February	1976
Northeast	NE	January	1976
East Midlands	EM	August	1974
West Midlands	WM	August	1976
Wales	WA	June	1974
Eastern	E	November	1974
North Thames	NT	August	1976
Southeast	SE	June	1976
Southern	SO	February	1975
Southwest	SW	November	1975

In preparation for high pressure transmission pipelines during the mid-1960s, dehydration of gas was recommended to reduce water accumulation in pipelines. Early dehydration processes were relatively simple, and water is known to have entered early high-pressure systems, the Super Grids, with drop out occurring preferentially at low points and changes in geometry. Dip pipes were therefore installed at known low points to collect accumulated water.

Reducing free water lowers susceptibility to ISCC. Operating pressure remains a relevant factor, as increasing pressure raises the gas dew point and increases the likelihood of condensation which is especially important when gas was compressed to higher pressures. Gas from the North Sea was required to be processed to ensure no water dropout took place in the transmission system and the gas bought was of 'pipeline ready' quality. The conversion to natural gas removed the risk of further ISCC but did not remove ISCC that had already occurred.

Initial Screening

Where the commissioning date of the pipeline is later than the completion date of the natural gas conversion programme, exposure to manufactured gas is not possible. Unless other evidence indicates otherwise, susceptibility to ISCC is not credible. Where this condition is satisfied, no further manufactured gas assessment is required.

Manufactured Gas Assessment

For pipelines commissioned before completion of the natural gas conversion programme, an assessment shall be performed to determine whether the pipeline transported manufactured gas and whether ISCC is a credible threat. The assessment shall review:

- ISCC history - A pipeline with confirmed ISCC will require further detailed work to justify repurposing for hydrogen service.
- Regional conversion date - Identify the applicable regional conversion period using historical records of the conversion programme. Pipelines commissioned before regional conversion shall be assumed to have potential exposure to manufactured gas unless evidence demonstrates otherwise. Conversion dates by LDZ are shown in Table D. 1. More localised conversion records may be able to demonstrate that the pipeline operated only with natural gas.
- Hydrotest date - A pipeline that transported wet manufactured gas for less than one year is not considered to be at credible risk of ISCC [72].
- Historical inspection records - Records of repairs, modifications, girth weld inspections, or other appropriate sources shall be reviewed for indicators of ISCC.
- Gas manufacturing process – Where available, the supplying gasworks and manufacturing process shall be identified. Different gas manufacturing plants produced gas with different compositions and dryness. A dry gas poses no ISCC risk. The level of dehydration is linked to the MOP with the dew point temperature increasing with pressure. Any wet manufactured gas poses a risk of ISCC. The carbon monoxide partial pressure for there to be a credible risk of ISCC is 0.41 bar, equivalent to transporting gas with 5 % carbon monoxide at 8.2 bar [72, 74].
- Evidence of wet manufactured gas service – Records and interviews shall be reviewed for evidence of wet manufactured gas service including dip pipes or other indicators of water accumulation management, or inability to demonstrate a pipeline has only seen natural gas service will require further research.

ISCC Further Research

Previous work has made recommendations on managing ISCC, including extending the planned P/18 scope to include work on pipelines formerly used to transport manufactured gas which could be affected by ISCC [75]. Relevant recommendations included:

- Hydrotesting as a means of assurance that a pipeline operating over 30 % SMYS would not fail by rupture.
- Investigation and advice on appropriate inspection methods to detect ISCC.
- Inspection of selected sections of potentially affected pipelines for ISCC at low points and bottom of line.
- Preparation of guidelines for detection.
- Inspection and defect acceptance limits for ISCC.

It is noted that the 30 % SMYS threshold may not indicate the likely mode of failure in hydrogen service. Any further research should be tailored to the specific asset under assessment.

Appendix E
Historical Girth Weld Quality and Inspection Practices

For this assessment the quality of all girth welds on the original pipeline and any modifications or diversions should be established using the records compiled as part of the review in Section 4.1. Any available information on weld defects will also be considered as part of the pipeline defect assessments in Section 4.4.4.

Girth welds may be associated with defects such as misalignment, peaking, burn-through, lack of penetration, inclusions, lack of fusion, porosity, undercuts, concavity, excess penetration, corrosion or cracks. Acceptability limits for these defects are provided by established welding standards such as BS 4515 [76], API 1104 [77] and GIS/P2 [78].

Historically, girth welds which have been inspected using radiography and classed as acceptable in accordance with established welding standards (e.g. BS 4515, API 1104) are considered to be good quality. The welding standards applied at the time and the type of NDT used to inspect girth welds following completion may therefore be used to confirm the welds are of good quality, however, the quality of girth welds in the national and local transmission systems was and is controlled through the following measures:

1. Application of pipeline recommended practice published by the Institution of Gas Engineers (IGE). The first transmission pipeline publication was IGE Communication 674 published in 1965.
2. Purchase of line pipe and fitting materials with adequate weldability. Gas industry specifications and standards started to be produced in 1968 with the formation of the Pipelines Operations Centre at Hinckley. Specifications included:
    a. The use of welding consumables (electrodes, filler wires, etc.) which give adequate strength and toughness, with good deposition characteristics.
    b. Specification and qualification of detailed welding procedures.
    c. Qualification of welders by means of a pre-contract test weld or by means of radiography of site welds.
3. Requirement for on-site supervision to ensure that the specified and qualified welding procedures are followed. The ERS Pipeline Inspector Approval Scheme was first introduced in April 1968, to train and approve welding inspectors. The requirement to use approved welding inspectors was a requirement on all gas industry pipeline construction contractors.
4. Inspection of completed girth welds. 100 % X-ray radiography inspection of field welds was introduced by Pipelines Department in 1969, and the Gas Council issued a technical specification, GC/PS/P2, for the inspection and acceptance of such welds in 1972, in line with published standards.

Pipeline girth weld quality can therefore be inferred by confirming whether the pipeline was constructed in 1972 or later. The ERS Data Scheme [79] may be used to confirm 100 % radiography and any recorded weld faults. Supporting records relating to girth weld quality include construction documents such as welding bar charts, weld inspection reports, welding standards and procedures, welder qualifications, repair records, daily construction logs etc.

Note that girth welds on pipelines constructed pre-1972 are not necessarily poor quality, however there is a chance that the weld was not inspected and therefore may contain defects which would not be acceptable in accordance with GIS/P2. Studies suggest that 14 % of welds made before 1972 contain defects which would not be acceptable to GIS/P2 [80]. The UKOPA Weld Quality Project investigated the quality of girth welds in pipelines that were commissioned before 1972. 27 girth welds were examined in detail. The majority of the girth welds dated from the period from 1968 to 1970, with the oldest from the 1950s and the newest from 1971. The diameter of the pipe ranged from 168.3-914.4 mm, and the grade from Grade B to X65. All of the girth welds were manual welds produced using the shielded metal arc welding process. The girth welds were inspected visually and using radiography. 22 were acceptable to BGC/PS/P2. Five were not. Four of the five were not acceptable due to a lack of root penetration. Subsequent examination determined that these were partial penetration welds and had come from intermediate pressure distribution pipelines, not transmission pipelines. The fifth weld contained a long linear indication (confirmed using ultrasonics). Seventeen girth welds, containing the most severe defects, were selected for further investigation: chemical analysis, tensile testing, impact testing and hardness testing. The tests showed that despite the presence of the defects the welds would be fit for continued service and the material properties are acceptable. It was concluded that girth welds constructed to standards in use pre-1972 are of good quality, and despite containing defects that would not be permitted in modern welds, remain fit for service [81].

It should be confirmed whether any girth weld failures have occurred on the pipeline post-commissioning or whether any girth weld defects have been identified post-commissioning through inspection. For weld inspections, such as those performed in accordance with the requirements of GDN/PM/P/18, the Specification for Working on Pipelines Containing Defective Girth Welds or Girth Welds of Unknown Quality [82], confirmation should be made of the inspection findings including the number, type and severity of the reported defects and whether they were found to be acceptable. It is recommended that welds which were rejected in accordance with P/18 are reassessed to confirm the conclusion. Experience has shown that inspections are carried out by welding contractors who often apply current acceptability limits rather than P/18 acceptability limits.

The use of any information taken from non-primary sources, and any inconsistencies identified across available sources, relating to girth weld quality should be documented. If the available weld records suggest there is uncertainty regarding the girth welds in the pipeline, then a sample of welds should be excavated and inspected to help improve understanding of the weld quality in the pipeline.

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