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Review

Inspection of Coated Hydrogen Transportation Pipelines

Shaik Asaaduddin Khwaja [1,*] and Shiladitya Paul [2,3]

1 St Edmund's College, University of Cambridge, Cambridge CB3 0BN, UK
2 Materials and Structural Integrity Technology Group, TWI, Cambridge CB21 6AL, UK
3 Materials Innovation Centre, School of Engineering, University of Leicester, Leicester LE1 7RH, UK
* Correspondence: sak91@cam.ac.uk

Abstract: The growing need for hydrogen indicates that there is likely to be a demand for transporting hydrogen. Hydrogen pipelines are an economical option, but the issue of hydrogen damage to pipeline steels needs to be studied and investigated. So far, limited research has been dedicated to determining how the choice of inspection method for pipeline integrity management changes depending on the presence of a coating. Thus, this review aims to evaluate the effectiveness of inspection methods specifically for detecting the defects formed uniquely in coated hydrogen pipelines. The discussion will begin with a background of hydrogen pipelines and the common defects seen in these pipelines. This will also include topics such as blended hydrogen-natural gas pipelines. After which, the focus will shift to pipeline integrity management methods and the effectiveness of current inspection methods in the context of standards such as ASME B31.12 and BS 7910. The discussion will conclude with a summary of newly available inspection methods and future research directions.

Keywords: hydrogen; hydrogen pipelines; inspection; NDT; NDE; pipeline transport

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1. Introduction

The increase in demand for energy, brought on by higher populations and standards of living, means that traditional, non-renewable fossil fuels are bound to be depleted at some point [1]. This fact, alongside rising concerns over global warming and the role that carbon-based fuels have to play in it, means that there is a strong demand for alternative fuels [1,2].

Hydrogen has quickly emerged as an attractive prospect to address this issue for a number of reasons. Firstly, fuel cells devices, specifically of the Proton Exchange Membrane (PEM) type, offer a higher efficiency and lower emission alternative to the internal combustion engine [2]. Additionally, hydrogen fuel cell electric vehicles (FCEVs) offer a longer range and a reduced refuelling time compared to "battery electric vehicles" [3]. Moreover, hydrogen has been poised to solve the issue of "decarbonising" heat, while reducing expenses and disruptions to consumers [3]. Another practical advantage that stands to be realised is faster refueling when hydrogen is used as an energy source [1]. Hydrogen is also a more energy-dense fuel compared to gasoline, with the energy in a kilogram of hydrogen gas being equivalent to that in 2.8 kilograms of gasoline [4].

However, the full realisation of the possibilities of hydrogen is contingent on a number of factors, one of them being a functional "hydrogen refuelling infrastructure" and the establishment of a "safe and efficient national infrastructure for hydrogen delivery and distribution" [1,2].

While there are a number of options available for long-range hydrogen transport such as shipping it in the form of liquified hydrogen, liquid organic hydrogen carriers (LOHCs) or ammonia, pipelines are the most economical option for hydrogen gas transport over medium to long range [5–7]. Specifically, this is true for distances of less than 1500 km and for volumes of more than 10 tonnes per day [5]. Additionally, with pipelines, there exists the possibility of blending hydrogen into existing natural gas pipelines—an important consideration given that it costs 10 to 15% of the cost of a new hydrogen line to re-purpose a natural gas pipeline to a hydrogen line [5].

While considering hydrogen transportation, it also becomes important to account for the deterioration of the pipeline. This tends to be seen in the form of Hydrogen Induced Cracking (HIC), Sulphide Stress Corrosion Cracking (SSCC) and Stress-oriented HIC (SOHIC) [8]. These forms of failure occur when atomic hydrogen finds its way into the interstitial spaces of the pipeline material and the Hydrogen Embrittlement (HE) that precedes such failures can be modelled either by the Hydrogen-Affected Localised Plasticity (HALP) model or the Hydrogen Enhanced Localised Plasticity (HELP) model [8].

To mitigate against damage resulting from hydrogen degradation, there are a number of available strategies, one of which is coating the exterior and the interior of pipelines [8]. The strategy/strategies are deployed based on the extent of degradation and/or the risk level [8]. This, ostensibly, necessitates reliable methods to monitor the extent of damage during the service of the pipeline.

Additionally, the fact remains that the failure of hydrogen pipelines has catastrophic consequences [9]. Ensuring the integrity of pipelines then becomes important, and non-destructive testing methods such as Magnetic Flux Linkage (MFL), Ultrasonic Testing (UT) and Eddy Current Testing (ET) offer an increasingly accurate method of detecting defects in pipelines, the majority of which are made from carbon steel, low alloy steel and, stainless steel [10,11].

So far, there has been very little research dedicated towards determining how the presence of coatings in hydrogen pipelines might affect the choice of inspection method for the purpose of pipeline integrity management. Therefore, this review aims to evaluate the effectiveness of inspection methods specifically for detecting the defects uniquely formed in coated hydrogen pipelines.

The review begins with a background of hydrogen pipelines and the defects usually seen in such pipelines. This section will also explore related topics such as the suitability of various pipeline materials and the issue of blended hydrogen-natural gas pipelines. The following section details the steps of pipeline integrity management and the methods currently being employed for this, including inspection of pipelines. The next section evaluates the effectiveness of current inspection methods, alongside standards such as ASME B31.12 and BS 7910 and finally the last section details new inspection methods and future research directions.

2. Background

2.1. Brief Description of a Hydrogen Pipeline

2.1.1. Choice of Pipeline Materials

As discussed earlier, hydrogen pipelines become commercially viable for transporting large volumes of hydrogen over medium to long distances [5]. Therefore, it would be reasonable to restrict the scope of this review to transmission pipelines, as opposed to shorter distribution pipelines. Given the higher pressures in transmission pipelines, they tend to be made using steel [12]. Current literature has suggested that the use of certain pipeline steels over others could allow cost savings of up to 32% [13]. These considerations alongside the need to optimise the qualities of pipeline steels for the required situation, make the choice of pipeline steel an important one. Therefore, this review shall also attempt to briefly outline the findings about the behaviour of different API 5L grades of steel in the context of hydrogen degradation.

2.1.2. Defects Unique to Hydrogen Pipelines

Figure 1 summarises the types of defects seen in pipeline steel due to hydrogen [8]. Table 1 explains how these defects are formed.

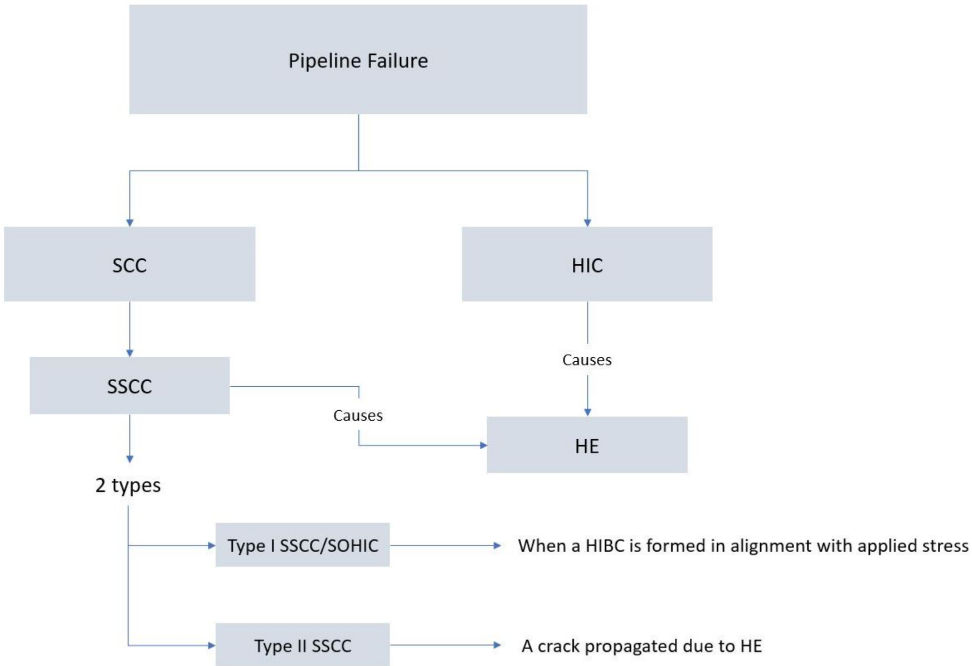

Figure 1. A summary of the types of hydrogen damage seen in pipeline steel.

Table 1. The defects caused by hydrogen in pipeline steels and their cause.

Reference	Defect	Description & Cause
1	Hydrogen Induced Cracking (HIC) [8]	HIC occurs when hydrogen recombines in the steel to form gaseous molecules in voids [14].
2	Hydrogen Stress Cracking (HSC)/ Stress Corrosion Cracking (SCC) [8]	Occurs at surface or near-surface [14]. Forms as a result of tensile static load and a corrosive medium being present together [15].
3	Hydrogen Induced Blister Cracks (HIBC) [14]	Occurs when the pressure exerted by molecular and atomic hydrogen in the material is high enough to form blisters [14].
4	Stress—Oriented HIC (SOHIC) [8,16]	SOHIC is also known as Type I SSC and occurs when HIBC is parallel to the applied stress [14].
5	Hydrogen Embrittlement (HE) [8]	HE is the result of hydrogen entering the steel either during manufacturing or due to exposure to hydrogen during service. This manifests in the form of deteriorated mechanical properties [14,15].

2.1.3. The Question of Blended Hydrogen Pipelines

Blended hydrogen-natural gas pipelines are of interest due to the existing infrastructure of natural gas pipelines; there is the possibility of re-purposing it to transport and store hydrogen to realise the benefits discussed earlier [17].

Considering the difficulties arising from the differing properties of natural gas and hydrogen, a reasonable approach that has been suggested is to first use the existing infrastructure to transport methane-hydrogen blends, understand the challenges arising from this, implement operational modifications as required and then progressively increase the percentage of hydrogen in the blend to 100% [17]. It is found that as the percentage of hydrogen in the blend increases, leakage flow rate increases, lower heating value increases and the energy cost of transporting the blend increases [17]. It is also suggested that up to 25% of hydrogen in the mixture by volume does not appear to markedly “increase the risk of explosion” [17]. Separately, it is further suggested that there are different levels of risk associated with the percentage of hydrogen in the blended pipeline [18]. Table 2 illustrates these findings.

Table 2. Hydrogen levels and their associated risks in blended pipelines [18].

Hydrogen Level in Pipeline	Overall Risk Level
Less than 20%	"Not significant"
20% to 50%	"Significant increase" in overall risk for service lines but the overall increase in risk in distribution mains is "moderate"
Greater than 50%	Impermissible level of overall risk

There are further factors to consider when hydrogen degradation of pipelines are discussed. Firstly, a distinction is made between higher pressure transmission pipelines and lower pressure distribution pipelines, with added hydrogen of less than or equal to 50 per cent in natural gas transmission pipelines needing "generally insignificant" modifications [18]. This figure, however, needs to be verified for every case [18]. Hydrogen degradation was found to be especially prevalent when the system is at high concentrations and pressures—common conditions where hydrogen is introduced into the pipeline at high concentrations [18]. Hydrogen was also found to reduce the pipes' endurance towards cyclical pressure changes (fatigue) and further crack growth from existing defects [18].

The material of the pipes factored heavily into the extent of hydrogen degradation observed. Common low-strength steels used in pipelines (API 5L A, B, X42, and X46) mainly experienced a reduction in ductility [18]. High-strength steels (having a yield strength greater than 100 ksi) tended to be more susceptible to HIC, while low strength steels were more likely to suffer from a loss in tensile ductility [18]. Faster crack growth and lowering of "fatigue endurance limits" were seen in carbon and low alloy steels, even at low pressures of hydrogen exposure [18]. Crack growth was more significant at ambient temperature as opposed to higher temperatures [18]. Conversely, Hydrogen ageing was not a prime concern for PE (polyethylene) and PVC (polyvinyl chloride) pipelines, with most elastomeric materials used in the pipelines being suitable for use with hydrogen [18]. However, compared to methane (a natural gas), hydrogen mobility was higher in polymer materials [18]. Consequently, hydrogen escaping through the walls of plastic distribution pipes was responsible for major loss of gas from the system [18].

Melaina et al. [18] also discussed the consequences for end-use systems, safety, the durability of pipeline materials, the risk of leakage, and the downstream extraction of hydrogen from the blended pipeline—a key consideration for applications requiring pure hydrogen.

While there have been discussions about potentially re-purposing natural gas pipelines for hydrogen transport, the economic and engineering feasibility of this has not been considered. Therefore, a summary of the challenges and opportunities of blended hydrogen pipelines is outlined in Table 3.

Table 3. Opportunities and Challenges of blended hydrogen pipelines.

Opportunities	Challenges
GHG (greenhouse gas) emissions are lowered if hydrogen is produced from sustainable energy sources [18]	Blending hydrogen into a methane pipeline could lead to a higher occurrence of "over-pressure, explosions, leakage and cracking [17]"
Replacing conventional diesel fuel with hydrogen (in fuel cells) for transportation could reduce emissions of sulfur dioxides and nitrogen oxides and improve air quality [18]	The presence of hydrogen means that it can interact with pipeline steels and cause HE [17]
The hydrogen-natural gas mixture, used as is for heat and electricity generation, is a cleaner fuel than pure natural gas [18]	Existing pipelines need to be modified by removing "undesirable parts," replacing valve fittings and ideally coating the pipeline internally to allow hydrogen to be transported at high pressures [5]
The cost of re-purposing NG lines for hydrogen transportation is significantly lower than building a new hydrogen line [5]	Operation of hydrogen lines requires thrice the compression power of NG lines and is more expensive [5]
Obtaining relevant approvals and ensuring compliance with procedures would mean that a new hydrogen pipeline would take 5–7 years to complete from initial planning to commission [19]	Retrofitting "turbo-compressors" to handle gas with a volumetric hydrogen content of more than 40% is not possible as yet [5]

2.2. The Effects of Hydrogen on Steels

Previous studies have hinted at the choice of pipeline material being a key determining factor in the susceptibility of the pipeline to hydrogen degradation. This sub-section provides a summary of the behaviour of different classes of pipeline steels under various conditions in the context of hydrogen degradation. For pipelines in general, key findings from literature include:

1. In the case of blended hydrogen-natural gas pipelines, before existing gas in the pipeline can be replaced, the feasibility of doing so has to be considered with respect to material fatigue, pipeline failure due to overpressure, and HE [20]. Using nitrided steel or higher grade pipeline steel was also said to improve safety [20]. The effect of coatings, however, needs further study to determine its effectiveness in preventing HE [20].
2. It has been suggested that scratches suffered by pipelines as a result of pigging are not likely to change their susceptibility to SCC [21]. However, it is said that if pigging were conducted in the presence of H2S, the negative impact of SCC on the pipelines could be more severe [21].
3. HE susceptibility is a contested issue, with some having reported that the HE susceptibility of structural metals rises as materials strength rises [22]. Others separately reported that fatigue crack growth depended on the pipeline steel and its "specific microstructural characteristics" [22].
4. A method was proposed to predict the changes in fracture toughness arising due to changes in "hydrogen concentration" [23]. This involved using "small punch test data of HE specimens", and finite element damage analysis "based on the multi-axial fracture strain-based damage model" [23].

While analysis of literature relating to each API 5XL grade has not been done for this review, existing literature relating their behaviour in various conditions in the context of hydrogen damage has been categorised in Table 4.

Table 4. An overview of findings in the existing literature about the properties of each pipeline steel grade.

Pipeline Material	Material Properties	Mechanical Properties	Blended Pipeline Suitability	Processing Conditions	Environmental Conditions	Testing & Analysis
X52 Steel	-	[24,25]	-	-	-	-
X56 Steel	-	[26]	-	-	-	-
X60 Steel	-	-	-	[27,28]	[29]	-
X65 Steel	-	[30]	-	-	[31,32]	-
X70 Steel	[33–35]	[25,36–40]	[37,41,42]	[43]	[36,44,45]	[46,47]
X80 Steel	[48,49]	[50–52]	-	[49,53–55]	[56–64]	[65]
X90 Steel	-	[66]	-	-	-	-
X100 Steel	-	-	-	-	[67]	-
Super Duplex Steel	-	-	-	-	[68,69]	-

3. Pipeline Inspection

3.1. An Overview of Pipeline Integrity Management

Pipeline inspection is one aspect of overall efforts to ensure the pipeline is safe. Pipeline integrity management is proposed to consist of three basic steps [11]. These include:

- *"Defect detection and identification"*: This is done through "inspection, monitoring, testing and analysis techniques."
- *"Defect growth prediction"*: The data collected is used alongside damage prediction models for this.
- *"Risk-based management"*: The origins of risks are studied, the likelihood of failure is estimated and the consequences of failure are examined.

There have also been alternative integrity management processes proposed [8]. The process of integrity management is also said to be a cyclical one, consisting of "Integrity Assessment" via inspection, "Managing Discovery" of information received from the inspection, "Remediation" which involves repairs and "Documentation" where data is used to assess performance, before moving on to "Integrity Assessment" again [8].

It appears that ideas in the steps outlined by both processes have significant overlap. Therefore, in further discussions, the more succinct terminology proposed by Xie and Tian [11] shall be used. Since this review focuses on the inspection of pipelines, we shall limit our attention only to "Defect detection and identification" with some discussion of "Defect growth prediction" as it tends to depend on data collected from inspection.

3.2. Defect Detection and Identification

This section briefly describes and compares the capabilities of the currently available inspection and testing methods.

First, we note the difference between structural health monitoring (SHM) and non-destructive evaluation (NDE). Table 5 summarises these differences [70].

Table 5. A comparison of NDE and SHM.

NDE	SHM
Use non-destructive testing (NDT) to determine condition of a structure	
Using readings taken by removable transducers and instruments to assess the integrity of structures	Readings are usually taken by permanently attached instruments and transducers
Usually conducted when machines are not in operation and measurements are irregular	Regular measurement during operation

3.2.1. Non-Destructive Evaluation (NDE)

We first consider the NDE methods available and how they work. Integrity management processes propose the need for a combination of periodic in-line inspections and external corrosion monitoring [8]. Before we look into these monitoring methods, current NDE methods are described. Table 6 then summarises and compares the advantages and disadvantages of these methods and whether they can be applied in ILI and/or external corrosion monitoring (ECM).

Ultrasonic Testing (UT)

Ultrasonic inspection encompasses the use of longitudinal sound waves ranging from 0.5 MHz to 25 MHz to detect defects in materials, though these longitudinal waves may undergo mode conversion upon interacting with defects [71]. The choice of frequency ensures that the wavelengths are of approximately the same size as the cracks or defects one may expect to find in the material [71]. Ultrasound is typically generated through the deformation of a piezoelectric crystal when an alternating current is applied to it [71]. There are a variety of techniques specifically used for inspecting pipelines:

Phased Array UT (PAUT)

A single crystal yields an "unfocused, divergent" beam of ultrasound along a straight line [71]. With multiple crystals, in an array, the time delay can be applied to each crystal to change the wave direction and inspect a larger area [15,71].

Time of Flight Diffraction (TOFD)

Time of flight diffraction or TOFD refers to when "two ultrasound arrays are used separately as a transmitter and receiver [71]". The receiver measures both the "effects of wave diffraction due to the edges/tips of defects in the pipe material"and the reflection of the wave [71].

Guided Wave Testing (GWT)

Guided waves testing (GWT) is useful when spot-testing is not necessary and the pipeline coating is challenging to remove [71]. It has a much longer range of up to 100 m compared to spot testing, but there is a trade-off in terms of the resolution [71]. This is due to the usage of lower frequency (10 MHz to 100 KHz) waves, that are able to travel further but are less effective in interacting with smaller defects [71]. There are also other drawbacks to this method, one being that it is not able to detect defects parallel to the length of the pipe [71]. But when considered as an initial screening method to determine where a follow-up is necessary with more precise methods, GWT has significant utility [71]. Heinlein et al. [72] also validated the use of GWT in a SHM system.

It is also suggested that GWT could be specifically used to detect corrosion at support sites along the pipelines [73]. It was further demonstrated that after implementing baseline subtraction followed by coherent averaging, the reliable detection of a 2 mm by 1 mm notch one pipe diameter away from the transducers was achieved in a 6-inch diameter steel pipe [74].

Microwaves NDE (MW)

With advances in technology dielectric materials with superior physical properties are replacing or being used with metals as coatings [75]. Microwave NDT works well for testing specimens with such coatings because, unlike traditional NDT methods, it has little absorption in dielectric materials [75]. Yet, it still interacts well enough with dielectric materials to respond to "structures and defects" under the dielectric coating [75]. The use of an "X-band rectangular waveguide with a vector network analyser" for NDE has also been posited [75]. Defects can then be imaged by analysing the reflection coefficient at the "waveguide aperture". Recent developments in the use of microwave NDE also involve the use of machine learning and artificial intelligence to mitigate the drawbacks of MW methods [76]. In the context of pipeline integrity management, apart from using the "Microwave Open-Ended Waveguide" technique for the detection of defects, "Guided Microwave Testing (GMT)" was shown to be capable of detecting corrosion under insulation (CUI), while "Chipless Radio-Frequency Identification Sensor System" was said to be applicable to SHM [76].

Magnetic Flux Leakage (MFL)

Magnetic flux leakage (MFL) first involves inundating the metallic surface of a specimen with a magnetic field and then "scattering ferromagnetic powder" on the surface of the pipe [71]. Where there are defects present, there is a discontinuity in the magnetic field, which can be recognised by the pattern formed by the ferromagnetic powder on the surface [71]. This disruption to the magnetic field could also be detected using a sensor such as a Hall Effect sensor [71]. While MFL tools nowadays have the capability of giving detailed data about the specimen, this data can be easily affected by noise [11]. MFL sizing models offer a solution to this issue and include the use of wavelet transform, fast Fourier transform and the Wigner distribution amongst other methods [11].

Electromagnetic Acoustic Transducer (EMAT)

An electromagnetic acoustic transducer (EMAT) consists of a coil positioned at the inner pipe wall surface [11]. EMAT is capable of detecting defects such as "cracks, weld characteristics and wall thickness variations" [11]. The method does not require any couplant to generate ultrasound as it uses Lorentz forces [11]. However it needs to be less than 1 mm from the specimen and even so, its "detection ability and efficiency" are lower compared to UT [11]. Signal processing methods similar to UT can be used for EMAT as well [11].

Eddy Current Inspection (ET)

Eddy currents—circular currents generated in a conducting specimen by virtue of "changes of a magnetic field passing orthogonally to the conductor"—can be used to determine defects in the pipeline walls as well [71]. This magnetic field is typically generated by a coil connected to AC. When there are defects present, the eddy current is disrupted and the presence of the defects can be established [71].

The depth of penetration of the eddy current is influenced by its frequency [71]. At high frequencies, with a low energy setup, the method only allows detection of skin-level defects [71]. Pulsed eddy current (PEC) can be considered for higher depth coverage, which is achieved by transmitting a "pulse or step function" through the coil [71].

An extension to typical eddy current inspection is movement-induced eddy current (MECT), where the change in the magnetic field is generated through the relative motion of a magnet with respect to the specimen [71]. This has the added advantage of generating stronger currents, which therefore allows for greater depth of inspection [71].

It has also been suggested that "Lorentz force eddy current testing", which uses the magnitude of Lorentz force experienced against the magnet moving relative to the specimen, can increase the depth to which defects can be detected [71]. This is also said of "magnetic eddy current", whereby magnetising the ferromagnetic specimen, increases the penetration depth of eddy currents by increasing the permeability of pipe walls [71].

Another extension of the application of eddy-currents is eddy-current induced thermography (ECIT) [77]. In ECIT, the specimen is induction heated and any cracks present cause changes in the flow of the induced eddy currents [77]. The resultant Joule heating is picked up at the specimen surface using an infrared camera and cracks as small as 0.23 mm in steel are claimed to have been discernible by a human operator [77]. However, the results described are obtained after the specimen was painted to improve its optical properties [77].

Radiograhy Testing (RT)

Radiography involves generating an X-ray of the specimen being inspected. There are methods available for pipelines, mainly the "double wall" method and the "single wall" method [71]. The orientation of the pipes differs during each method, such that X-rays pass through both walls before reaching the detector plate in the former, and only one wall before reaching the plate in the latter [71]. The method chosen depends on the accessibility of the area of inspection among other considerations, with the double wall method requiring multiple exposures before a complete picture of the pipe can be generated [71]. Apart from the apparent safety concerns of radiation, other drawbacks involve the need for the results to be interpreted by trained personnel.

A possible technique for improving the visibility of results is suggested in Eckel et al. [78], whereby a new technique is used to digitise radio-graphs and extract statistical characteristics as a means to measure the "granularity of film noise".

Electromechanical Impedance (EMI)

This technique involves the use of piezoelectric transducers and using the difference in mechanical impedance to identify damage [79]. A structure's structural mechanical impedance is a function of properties like "stiffness, mass and damping", therefore the presence of corrosion damage causes changes in structural mechanical impedance [79]. This then causes the electrical impedance of the transducer to change, enabling corrosion damage monitoring [79].

Infrared Thermography (IRT)

IRT involves utilising infrared waves to analyse thermal information that can then be mapped to a temperature variation [80]. It was suggested that IRT has the potential to be used for the detection of CUI starting from a 15% reduction in wall thickness, but that the ability to do this is dependent on the temperature of the pipe and how close water injection is to the pipe surface [81]. There are also advantages to be realised by using IRT with drones to increase the area of inspection [82].

Magnetic Barkhausen Noise (MBN)

MBN is used for determining the present "residual stress and fatigue aging of ferromagnetic materials" [15]. This is achieved by analysing the signals of magnetic and acoustic emission, caused by domain reversal during magnetization [15]. This allows for the determination of stress as well as microstructure of ferromagnetic materials [15].

Visual Testing (VT)

VT of a specimen, while cheap, cannot match the capabilities of the other inspection methods discussed here [83]. Its usefulness is limited to monitoring existing defects or for simple inspections [83]. Its effectiveness can potentially be improved by using it in conjunction with tools that enable automatic detection of defects [84].

Table 6. NDT methods and a comparison of their advantages and disadvantages in the context of coated pipelines.

NDT Method	Advantages	Disadvantages	Applicable to ILI	Applicable to ECM
UT	"High penetration depth" and can measure internal and external coating as well as wall thickness [15]. Also allows estimation of external corrosion [15]. Has a higher confidence level than MFL [11].	Requires liquid coupling between transducer and pipeline, making it difficult to conduct ILI with gas pipelines [11]. UT signals also need to be de-noised to obtain valid information [11].	✓	✓
MW	Able to detect and image defects in metals under dielectric coatings [76]. Changes in the thickness of coatings can also be monitored [75].	Current methods require significant interpretation of data, display unclear "defect geometry", and have a low "spatial resolution" [76].		✓
MFL	The required resolution can be chosen by varying parameters such as sensor spacing [11].	Only works well in easily magnetised metals and may cause the pipe to become magnetised indefinitely resulting in product flow restrictions [11,15].	✓	
EMAT	No need for couplant, making it ideal for gas pipelines [15]. Literature provides validation of EMAT for identifying and sizing SCC cracks and corrosion in gas pipelines [11].	The transducer needs to be less than 1 mm from the specimen and even so, its "detection ability and efficiency" is lower compared to UT [11]. This could present a challenge for coated pipelines.	✓	
GWT	Not necessary to remove pipeline coating across the entire area of inspection [71]. Useful as an initial screening method and for SHM [71,74].	Unable to detect defects oriented along the length of pipe and there is a trade-off between range and resolution [71].		
EC	Responsive to a variety of parameters and usable over a wider temperature range [15]. It is also lightweight and cheap to deploy [15].	Can only be used on materials that conduct electricity, is highly dependent on "lift-off distance" and is unable to detect "external defects" through the pipeline wall [11,15].	✓	
RT	No preparation of the surface is necessary and the insulation does not have to be removed before inspection [15].	Potential danger from radiation to living things nearby [15].		✓
ECIT	Non-contact and capable of "sub-millimetre/millimetre crack" detection [77].	Possibly necessary to paint the specimen to improve its "optical properties" and obtain better sensitivity [77].		
EMI	Sensitive to localised corrosion and suitable for SHM of pipes [79].	Currently only demonstrated to work for stainless steel plates [79].		
IRT	Could be incorporated with technology such as drones to quickly inspect large sections of the pipeline for CUI [82].	Ability to detect CUI depends on the temperature of the pipeline and how close water is located to the surface [81].		✓
MBN	Able to detect microstructure and stress present in materials quickly without any harm to the operator [15].	Challenging to find "a consistent behaviour of the MBN signal". The signal "can only be picked up near the surface of the materials" [15].		
VT	Operation is cheap and simple [15]. Could potentially be automated [84].	Highly dependent on the operator and only suitable for defects on the surface [15].	✓	✓

While comprehensive in its scope, Ma et al. [15] and other existing literature did not appear to have a study dedicated to evaluating the effectiveness of pigging in coated hydrogen pipelines. Separately, it was suggested that UT can be used to determine the health of a polymer internal coating by detecting "removed or improper coating" [85]. But this method, which utilises echos to generate a standoff signal, is unable to detect the gradual thinning of the coating [85]. If the aim is to determine metal loss through the coating, UT is also proposed, but three measurements are required: the thickness of the coating and steel, the steel alone and the coating alone [85]. MFL and EMAT are unlikely to be able to work given that the polymer does not conduct electricity [85].

At this point, it will be helpful to make a distinction between the implications of a blended hydrogen pipeline and a pure hydrogen pipeline. A blended hydrogen pipeline containing NG and hydrogen could possibly contain impurities such as hydrogen sulphide and water which can cause pipeline corrosion that results in the generation of hydrogen. In this scenario, a coating may assist in mitigating corrosion. Conversely, using a physical coating to mitigate HE found limited success [86]. Therefore, given that HE will be the main concern in a pure hydrogen pipeline, coatings will likely have limited utility in preventing hydrogen damage.

It is also worth noting that molecular hydrogen needs to transform into atomic hydrogen before it can get into the steel pipeline [87]. Turnbull [87] provided a detailed account of the processes by which hydrogen diffusion and trapping occur in metals, but this falls outside the scope of the review and will hence not be discussed further.

Additionally, related to coated hydrogen pipelines is the need to evaluate the feasibility of converting an existing natural gas pipeline to a blended pipeline [20]. However, currently only the nitriding of the inner surface of the pipe appeared to be under consideration [20]. A possible extension of current work would be to evaluate the feasibility of different coating materials, not just for their effectiveness in reducing corrosion but also in enabling easier in-line inspection (ILI).

We now shift our attention to the outer surface of the pipeline. A different kind of damage tends to be seen on insulated metallic surfaces. Corrosion under insulation (CUI) is defined as "a severe form of localized, external corrosion" that is usually seen "on insulated carbon and low alloy steel and stainless steel equipment" in operation "at or below 175 °F [88]". This is therefore not a concern specific to hydrogen pipelines, but to those carrying hot liquids. CUI is seen commonly in the "chemical/petrochemical, refining, offshore, and marine/maritime industries" [88]. There are severe consequences if it is not detected and dealt with, such as disastrous "leaks or explosions" and "equipment failure" among other consequences [88]. CUI is a concern for insulated pipelines, however, since it is unlikely for hydrogen pipelines to operate at temperatures in the CUI domain, this does not need to be considered in the scope of this review.

3.3. Prediction Models

This section will summarise recent trends in prediction models—the second key step in pipeline integrity management.

A model has been developed to analyse the kinetics of fracture in protective coatings/delamination growth of metal and steel bodies [89]. It considers a "penny-shaped" crack propagating parallel to the pipe wall, and uses the fact that the "driving force" for such cracks is the "internal pressure of accumulated hydrogen gas in the delamination cavity" [89]. Critically, the importance of this study is on account of the fact that HIC growth was considered under "real" gas conditions as opposed to "ideal" gas conditions [89]. This enables the model to be used to make higher accuracy predictions to be made about the lifetime of pipelines.

A different approach involved attempting to use cohesive zone modelling (CZM) alongside hydrogen diffusion to model "hydrogen-induced fracture initiation in a hot rolled bonded clad steel pipe [90]." This involves considering a traction separation law (TSL) to describe the response of "cohesive elements" along a fracture path [90]. The TSL in turn is characterised by cohesive parameters known as the critical cohesive stress (σ_c), the critical separation (δ_c) and the cohesive energy (Γ_c) [90]. Depending on the concept being used to describe the effect of hydrogen on steel (e.g. HEDE, HELP, or combined) two out of the three cohesive parameters can be independently varied to account for changes in hydrogen concentration [91]. 2D coupled hydrogen diffusion and CZM were used and it was determined that for a pipe with made API X60 with a 316L clad, best fit to experimental results was achieved when cohesive stiffness $(\kappa_n) = 4 \cdot 10^6$ MPa/mm and $\sigma_c = 1210$ MPa [90]. A possible extension to this could be using a 3D modelling approach to investigate the lack of agreement between experimental and predicted fracture initiation points in air and "hydrogen influence" [90].

Providing a more comprehensive review of CZM, Jemblie et al. [91] reported that the discussed predictive method of coupled diffusion and CZM works well for replicating "single experimental results" by adjustment of the cohesive parameters, but encounters difficulties when transferred to other hydrogen systems. Examples of this include the method not being able to rationalize enhanced crack growth under higher pressures and higher than predicted levels of local hydrogen concentration due to dislocation transport. It is suggested that better agreement with results could be achieved by determining the input parameters for the system under study. This seemingly implies having to conduct extensive testing for every new model under study. A possible direction to explore could be a review to identify systems that encounter similar difficulties with the method and provide a quantification of the degree of disagreement between experimental and predicted results.

Now, in the context of corrosion, there was a distinction drawn between "deterministic" and "probabilistic" models for pipeline corrosion growth [92]. These models largely describe the growth rates of pitting—the most serious risk in pipeline integrity [92]. The models discussed and a brief description of them are as follows [92]:

- Deterministic
  - "Single-value corrosion growth rate model": Utilises a corrosion growth rate that is constant for modelling over the required period.
  - "Linear corrosion growth rate model": Assumes corrosion growth is a linear function of time.
  - "Non-linear corrosion growth rate model": Assumes corrosion growth is a non-linear function of time with soil and pipe material being parameters that can be controlled.
- Probabilistic
  - "Markov model: Uses a "continuous-time, non-homogeneous linear growth approach" using "initial pit-depth distribution" and a "soil-pipe dependent parameter".
  - Monte-Carlo Simulation: Mathematical models of the specimen are solved a large number of times to obtain a "distribution of alternative possible values about the nominal point". This is commonly used to determine the uncertainty of a "deterministic calculation".
  - "Time-dependent generalised extreme value distribution": Uses the corrosion rate distribution of a "generic textural soil" that varies with time.
  - "Time-independent generalised extreme value distribution": Uses the corrosion rate distribution of a "generic textural soil" that does not vary with time.
  - Gamma process: A continuous probability distribution that is dependent on a scale and shape parameter. An assumption that is inherent with the Gamma model is that the defects are detectable by ILI tools.
  - "Brownian motion with drift" model: Treats corrosion as a "stochastic process independent increment". The model suits processes that has alternating increases and decreases and is thus ideal for corrosion due to its alternating "active and passive" behaviour.

4. Evaluation of Current Pipeline Inspection Methods for Hydrogen Pipelines

The following section attempts to evaluate current inspection methods' suitability for the detection of defects commonly seen in hydrogen pipelines. First, the standards relevant to each type of defect are considered, and the methods' capabilities are considered. Then, the inspection challenges arising as a result of coatings are considered.

4.1. Standards

It is important to note that these standards serve as guidelines and that the exact acceptance criteria would be dependent on the manufacturer and the exact circumstances in which the pipeline is being used. Stewart [93] explains the use of ASME and API codes in the context of in-service inspection in great detail. Table 7 provides an overview of standards that are relevant to each type of defect formed in pipelines during operation.

Table 7. An overview of the acceptance criteria for each defect produced during operation according to ASME B31.12 and BS 7910 [94–97].

Defect	ASME B31.12	BS 7910
Fatigue Crack	Refer to API 1104	Clause 8
SCC		Clause 10.3.3
HIC		Clause 10.3.3
Corrosion		Clause 10.3.2

Table 8 evaluates some of the discussed NDT methods and their sensitivity to the defects associated with hydrogen damage.

Table 8. An evaluation of the discussed NDE methods in relation to the hydrogen damage that they can inspect.

Method	Hydrogen Damage	Evaluation
UT	HIC, HSC, HIBC, SOHIC [15]	UT tools can detect, with a 95% confidence level, the affected area with a tolerance of ±0.3 mm to ±0.6 mm. However, the requirement for coupling means this would be difficult to do in-line [11]
EMAT	HIC, HSC, HIBC, SOHIC [15]	Isla and Cegla [98] describes an "8-element EMAT phased array" at an operating frequency of 1 MHz being able to detect defects with a width of 0.2 mm and a depth of 0.8 mm present on the opposite surface of the array.
RT	HIC, HSC, HIBC, SOHIC [15]	The choice of an image quality indicator (IQI) and subsequent processing will determine the sensitivity of the RT conducted [99]. The smallest IQI appears to be 1mm in diameter. [99]
MFL	"Metal loss" (e.g., corrosion) [15]	Statistical analysis of MFL data to obtain defect shape parameters can reach up to 90% accuracy for length, 84% for width and 78% for depth [100]. Niese et al. [101] describes combining EMAT, MFL and EC to accurately measure the wall thickness of a specimen and determine the location of metal loss in the wall of the specimen. However, the sensitivity of this method is not discussed.

4.2. Coatings

It is also worth discussing the effectiveness of these inspection methods in the context of coated pipelines. To this end, the coatings commonly used to counter HE and their efficacy are first discussed in this sub-section.

4.2.1. Effectiveness of Coatings

Before the effectiveness of coatings can be discussed, they need to be categorised. Current literature does not appear to have a consensus on how coatings should be categorised.

For instance, Bhadeshia [102] divided coatings up into two categories—brittle and ductile, whereas Michler and Naumann [103] appears to group coatings according to whether they are "on top" or "diffusion" coatings.

To aid further discussions about inspection methods, this review shall categorise coatings as metallic and non-metallic. Metallic coatings will encompass the metals and alloys described in current literature. Non-metallic coatings will then refer to coatings consisting of compounds. Table 9 categorises coatings and evaluates their effectiveness against hydrogen damage.

The following table outlines categories of coatings and their usefulness in reducing HE.

Table 9. Categorisation of coatings and their effectiveness.

Type of Coating	Description
Metallic coatings [102,103]	Electroplating high strength steels with cadmium (Cd) or zinc (Zn) can act to mitigate corrosion [102]. However, this process can cause hydrogen to enter the steel; hence, the specimen needs to be put through de-embrittling' by heating for about 8 to 24 h to enable "diffusible" hydrogen to leave the metal [102]. In the case of 304 austenitic stainless steel, aluminium (Al), copper (Cu), nickel (Ni) and Zn were electroplated onto the specimen with differing degrees of success [103]. Zn and Ni, for instance, were found to be ineffective at protecting the underlying steel against HEE (Hydrogen Environment Embrittlement) [103]. These coatings were found to have fractured at "very low strains" in tensile testing, causing the specimen to come into into contact with hydrogen, resulting in the initiation of HEE [103]. Cu appeared to be the more successful coating—with commendable tensile ductility, and adhesion [103]. However, parts with improper coating and "pinholes" were found to act as points of failure for the coating [103].
Non-metallic coatings [102–104]	Coatings made of compounds were found to have significant utility. Black oxide is shown to lower the ingress of atomic hydrogen into steel and slow down the formation of surface cracks arising from lubricants [102]. Aluminium consisting of MAX phase coatings was also found to be functional as a "protective coating" at high temperatures [104]. NiP and Ti-DLC coatings were found to have the same problems seen in "on top" coatings of metals: cracking was seen at low strains, and hydrogen could come into contact with the specimen being protected [103]. Categorised as "hard coatings", compounds such as TiC, TiN, BN, TiO_2 and WC are able to act as effective barriers against hydrogen ingress [102]. However, their effectiveness is dependent on "service conditions", the presence of defects in the coatings and structural integrity of the coatings [102].

4.2.2. Monitoring Coating Health

There is a need to ensure that coatings are operational and effective. This means that monitoring coating health becomes necessary. In this effort, considering standards allows one to plan how this might be done. ISO 9587:2007, ISO 9588:2007, GB/T 13322-1991, GB/T 19349-2012 and GB/T 19350-2012 are possible standards that could be used to ensure the protection against HE provided by the coatings is satisfactory [105].

Cumulatively, considering the standards for both HE protection and testing, there are a number of tests to be considered, some of which include [105]:

- The "Copper-Hydrogen embrittlement test"
- The "inclined wedge method" to test for residual embrittlement
- The "incremental step loading method" to test for hydrogen embrittlement threshold

However, given that this review focuses on NDT, the possibility of inspecting coatings using NDT is also considered in the following sub-section.

4.2.3. The Effect of Coatings on the Choice of Inspection Method

Given the different requirements of each NDT method, some challenges will be experienced due to the coatings when selected NDT methods are used to inspect the pipeline. These include:

- Thickness of coating: The distance between the sensor and metal surface due to the coating layer (known as lift-off) reduces the sensitivity of inspection [106]. The lift-off itself may vary due to the uneven thickness of the coating, complicating matters further [106]. This is likely to affect inspections of pipeline conducted using EC due to its dependence on lift-off [15].
- Conductivity of Coating: Coating conductivity may again interfere with methods such as EC [107]. Additionally, since MFL works best in metals that are easily magnetised, if the coating possesses this property, it may interfere with MFL inspections of the pipeline.

Therefore, it becomes apparent that, depending on the coating, some NDT methods have to be ruled out. The material of the coating would also determine the NDT method used to inspect the coating itself. Table 10 attempts to provide an overview of how the choice of NDT method would change depending on the coating type and the subject of inspection.

Table 10. A summary of how NDT method choice is affected by coating type when the subject of inspection changes.

	Metallic Coatings	Non-Metallic Coatings	All Coatings
Subject of Inspection: Pipeline	As explained earlier, if the coating is conductive, it could interfere with EC inspections of the pipeline [107]. The same is likely to be the case for MFL inspections if the coating is easily magnetised. There appears to be a gap in literature regarding inspecting pipelines with metallic coatings.	If the coating is dielectric, MW testing can be considered [106].	A traditional UT inspection of the pipeline material would be hard to perform due to multiple material surfaces and the need for coupling [106]. Non-contact ultrasonic techniques have been developed, but these have their own limitations [108]. For instance, laser ultrasonic requires the sample to have a finish surface "like a mirror" while capacitive ultrasonic transducers involve a complicated sample preparation process [108].
Subject of Inspection: Coating	Traditional UT relies on a change in acoustic impedance to make thickness measurements [85]. Hence, inspection of coatings using traditional UT is likely to produce stronger signals if the pipeline material and coating have differing acoustic impedance.	Traditional UT could potentially be used for thickness measurements of the coating [85]. Techniques that such as MFL will not work for insulators [85]. There is a potential for holiday inspection to be used for insulator coatings [109].	Visual inspection would be applicable for all types of coating but is subjective [15].

5. Novel Inspection Methods

Some novel and upcoming inspection methods are summarised below:

- A new method for validating GWT that "enables the operator to combine the ability of FE analysis to predict the signals reflected from a large number of different defect cases with the complex geometric and environmental effects specific to the particular pipe structure which cannot be effectively simulated" [72]. This method can be extended to methods other than GWT [72].

- A new method for characterising pitting resistance: "ultrasonic relative attenuation coefficient of high-order cumulant" is used to reduce Gaussian noise and tease apart noise caused by changes to the microstructure during corrosion [110]. This finding can then be used for characterising pitting resistance [110].
- A new "state-of-the-art" method for monitoring corrosion using permanently installed transducers is proposed that results in "repeatability values of 23 nm and 46 nm in the thickness measurements of a mild steel sample over the periods of 1 h and 24 h [111]".
- A new method uses electromechanical impedance to track corrosion-induced thickness loss [79]. A piece of PZT (lead zirconate titanate) is attached to a steel plate and, "using the direct and converse piezoelectricity effect of the PZT transducer, the discrepancy in the mechanical impedance of the stainless steel plate caused by corrosion can be identified by the discrepancy in the admittance signature of the PZT transducer [79]". The method was found to differ in its measurement of corrosion degrees, from actual corrosion by a maximum of 4.11% [79].
- A new method for simultaneous crack detection and thickness measurement using a single probe is discussed [112]. It was found that "crack-like defects with depth 0.3 mm (0.2λ) or higher can be detected" but the "amplitude drop value cannot be used to estimate the size of defects of 3mm depth or larger [112]".
- The use of water immersion UT allowed coating thickness to be measured with a lower degree of error. In particular, the time-of-flight (TOF) of the "reflected echo on the time-domain waveform" was determined [113]. Although this will require further study, it has been theorised that this could be adapted to other types of coating materials in water [113]. An interesting extension to this study would be to determine if this could be deployed in-line.

6. Possible Areas of Future Research

6.1. Risk Assessment of Natural Gas Pipelines

There appears to be limited literature about the inspections that would be necessary to ascertain if a given natural gas pipeline would be feasible to convert to a blended pipeline. Further research is needed to understand the behaviour of such pipelines in the event of a leak. The Joule-Thomson coefficient of natural gas is different from hydrogen and this offers some challenges as well.

6.2. Inspection of Coating Pipelines

The need to ensure the integrity of coated hydrogen pipelines means that there is a need to investigate the choice of coating for blended or hydrogen pipelines. Most of the research thus far has focused on pipelines transporting natural gas where the source of hydrogen has been the cause of corrosion processes. In such cases, the use of coatings could mitigate corrosion and thus hydrogen damage. However, when pipelines are used to transport hydrogen gas, the mechanism of damage is different and this needs to be carefully considered. Additionally, the implications of various coatings on existing inspection methods also need to be considered.

6.3. Investigation of properties of pipelines steels

Based on the summary of research in Table 4, it appears as though X80 and X70 are the most researched grade of steel—perhaps due to the need to balance economic considerations with performance. Higher strength steels (having a higher strength-to-weight) ratio allow for weight saving. Understanding clearly which combination of microstructural features, environment and stress levels lead to HE would enable more informed decision-making about the choice of pipeline steel used in hydrogen pipelines.

7. Conclusions

In conclusion, this review paper attempted to provide a brief background to the issue of inspecting hydrogen pipelines, evaluate existing inspection techniques and suggest possible directions for future research. The key findings from this review are:

- Hydrogen damage is a known issue, and it is difficult to detect.
- Coatings are used to mitigate corrosion, however, attention must be given to the type of coatings used. In hydrogen pipelines, the coatings currently in use do not stop hydrogen from permeating the steel surface.
- Inspection methods are available to evaluate hydrogen damage, each with its associated advantages and disadvantages. The choice of an inspection technique is dependent on the application environment and required accuracy among other factors.
- SHM is a desirable method, but finding a suitable SHM technique is challenging and needs to consider not only the technical requirements but also cost (both capital and operating expenditure).

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Abbreviations

The following abbreviations are used in this manuscript:

PEM	Proton Exchange Membrane
FCEV	Fuel Cell Electric Vehicles
LOHC	Liquid Organic Hydrogen Carriers
HIC	Hydrogen Induced Cracking
SSCC	Sulphide Stress Corrosion Cracking
SOHIC	Stress Oriented Hydrogen Induced Cracking
HE	Hydrogen Embrittlement
HALP	Hydrogen-Affected Localised Plasticity
HELP	Hydrogen Enhanced Localised Plasticity
MFL	Magnetic Flux Leakage
UT	Ultrasonic Testing
ET	Eddy Current Testing
HSC	Hydrogen Stress Cracking
SSC	Stress Corrosion Cracking
HIBC	Hydrogen Induced Blister Cracks
PE	Polyethylene
PVC	Polyvinylchloride
GHG	Greenhouse Gas
NG	Natural Gas
NDE	Non-Destructive Evaluation

NDT	Non-Destructive Testing
ECM	External Corrosion Monitoring
PAUT	Phased Array Ultrasonic Testing
TOFD	Time of flight Diffraction
GWT	Guided Wave Testing
MW	Microwave NDE
GMT	Guided Microwave Testing
EMAT	Electromagnetic Acoustic Transducer
RT	Radiograhy Testing
EMI	Electromechanical Impedance
IRT	Infrared Thermography
MBN	Magnetic Barkhausen Noise
CUI	Corrosion Under Insulation
CZM	Cohesive Zone Modelling
TSL	Traction Separation Law
ILI	In-line Inspection
PZT	Lead Zirconate Titanate
PEC	Pulsed eddy current
VT	Visual Testing
TOF	Time-of-flight
MECT	Movement-induced Eddy Current
ECIT	Eddy-current Induced Thermography
SHM	Structural Health Monitoring
IQI	Image Quality Indicator
HEE	Hydrogen Environment Embrittlement

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