HYNTS CORROSION

Summary Report

National Gas Transmission plc

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1 EXECUTIVE SUMMARY

Pipeline networks in Great Britain (GB) utilise a variety of corrosion protection techniques in order to protect their pipelines and other assets from damage. The first line of defence against external corrosion is the application of protective coatings and paints. The use of high-quality coatings limits corrosion to only two areas, microscopic points of missing coating known as holidays and areas of coating damage. On steel pipelines, cathodic protection (CP) is often used to offer protection to these uncoated areas.

This work has investigated whether converting pipeline networks to hydrogen could lead to an increased corrosion risk to the pipelines. First, the corrosion mechanisms present on GB pipeline networks were discussed, and the potential impact of hydrogen on those mechanisms was researched in the literature. The following mechanisms and findings were discussed:

- General Corrosion (External Corrosion).
  - As hydrogen is a natural byproduct of the corrosion reaction, increased hydrogen concentrations are not thought likely to increase corrosion rates.
- Pitting Corrosion.
  - While hydrogen could in theory influence the initiation of a pit, the corrosion reaction at the bottom of a pit, which leads to wall loss is the same chemical reaction as general attack corrosion, and therefore hydrogen is not expected to increase corrosion rates.
- Crevice Corrosion.
  - Hydrogen has been shown to increase rates of corrosion in stainless steel but research is very limited in pipeline steels.
- Corrosion under Insulation (CUI).
  - As with general attack corrosion, hydrogen is a product of the reaction and therefore is not expected to accelerate corrosion.
- Stress Corrosion Cracking.
  - GB pipelines are not considered at risk of internal stress corrosion cracking as they transport dry gas.
  - The mechanisms by which hydrogen could affect Near Neutral Stress Corrosion Cracking are not fully understood in the literature at this time. However, hydrogen embrittlement is suspected to play a role.
- AC Corrosion.
  - Hydrogen does not influence the mechanisms by which AC corrosion occurs.

Then the corrosion prevention mechanisms present on the network were discussed, along with the potential impacts of hydrogen on their efficacy. Pipelines utilise both coatings and paint to provide a physical barrier between the steel pipeline surface and the environment. When considering buried pipelines, which are more challenging to inspect, four common coating types were identified. These were Fusion Bonded Epoxy (FBE) and Coal Tar Enamel (CTE), which account for most pipelines, as well as Cold Applied Laminate Tapes (CALTs) and Multi-Component Liquids (MCLs). These were taken forward for the test program.

It was considered that hydrogen could have two possible detrimental effects on paints and coatings. Atomic hydrogen accumulates in the steel-product interface and recombines to build up pressure- causing the bond between steel and the product to fail. The process is known as hydrogen blistering. However, if the hydrogen can diffuse through the coating/paint at a rate faster than it is able to diffuse through the steel, it will not be possible for a volume of hydrogen to build up. Considering the difference in density between steel (broadly 7.75 to 8.05 g/cm^3) and common coating materials

such as FBE (broadly 1.3 to 1.5 g/cm^3), it is expected that coating and paint materials are unlikely to trap hydrogen effectively.

It is also possible that hydrogen could react chemically with the bulk of the coating or paint, causing changes to the chemical structure of the material which could lead to it breaking down and no longer protecting the pipe. However, many of the component materials identified during this work are listed as compatible with hydrogen in numerous industrial standards, which gives confidence that this is unlikely.

The test program exposed the 4 coating types (FBE, CTE, CALT and FBE+MCL) to hydrogen flux rates considered as realistic but conservative for a pipeline carrying 70 bar hydrogen for a period of 7 weeks. The condition of the coating was measured periodically using electrochemical impedance spectroscopy (EIS), and subsequently the samples were subjected to pull off testing and optical microscopy analysis of the coating/steel interface. No notable differences were recorded between the hydrogen exposed samples compared to the control samples.

Internal standards for the operation of pipelines were reviewed to identify areas where changes would be needed to safely operate pipelines in hydrogen service. As the literature review and test results offer no strong evidence that in service coatings would be unsuitable for hydrogen service. Overall, no changes to the policies and procedures are recommended at this time regarding corrosion control.

1.1 Conclusions

The following conclusions are therefore drawn from this program:

- There are a number of credible corrosion threats to GB pipelines which are all focussed on mechanisms where moisture can reach the external surface of the pipe. Additional corrosion-based mechanisms are not expected in a hydrogen transport scenario.
- Of the credible corrosion mechanisms, only pitting, crevice corrosion and Near Neutral SSC are believed to be possibly influenced by hydrogen.
    - Hydrogen could influence the initiation of pits but then would not be expected to accelerate corrosion within pits.
    - The effect of hydrogen on ferritic carbon steels used for NTS components is not clear. Initiation and propagation of crevices is enhanced by hydrogen in stainless steels.
    - Hydrogen is known to accelerate Near Neutral SCC in stainless steel, but there is an absence of data in carbon steel so the extent of its possible influence on GB pipelines is currently unknown.
- Of the current corrosion protection systems used on GB pipelines, it is believed that deleterious interactions between hydrogen and coatings, paints and CP systems are unlikely. Current hydrogen standards such as ASME B31.12 provide guidance on the appropriate use of sleeves and repairs.
- The test program has demonstrated that over a 7-week exposure time no deleterious effects of hydrogen exposure were noted on 4 ex-service coatings (FBE, CTE, CALT and FBE+MCL). This gives confidence that hydrogen would not have a deleterious effect on pipeline coatings in the short term. No change in observed corrosion was noticed on any of the samples.
- A review of relevant policies and procedures highlighted key questions for a hydrogen transport scenario. As this work suggests that there would be no initial change to coating integrity or corrosion rates, no changes to approach is recommended. However, hydrogen conversion would require reconsideration of several safety related policies in terms of risk to personnel etc.

1.2 Recommendations

The following recommendations are made from the findings of this program:

- While the test program found no deleterious effects of hydrogen, this short term testing cannot be used to confidently forecast the long-term behaviour of coatings on the network, even though it does give confidence that conversion can be achieved. In the event of conversion to hydrogen transport, additional network surveillance will be key to confirm the safe operation of the network. This should include the close monitoring of coating survey data, inline inspection data and other tools to detect areas where corrosion rates may increase. Networks should also consider more invasive procedures at periodic intervals to ensure that coating adhesion can be tested over long term exposure to hydrogen transport.
- The additional surveillance mentioned above should also allow for data to be collected to investigate the possibility of other mechanisms being influenced by hydrogen in the long term that were not included in the test program. These should include NNSCC and the possible interactions of hydrogen with pipeline sections with CP achieving polarities close to or more negative than -1150 mV.
- Moving forward, networks should seek assurance from coating, paint and repair manufacturers as to their products' compatibility with hydrogen. It should be noted that it is possible that coatings/paints/repairs applied to a pipeline in active hydrogen service could have their curing processes influenced by permeating hydrogen, and this test work has not investigated this possibility.
- Significant learnings and guidance can be found from existing hydrogen pipeline standards and operators with hydrogen pipelines globally. The current understanding is that the corrosion protection and pipeline surveillance systems used with existing hydrogen pipelines are very similar to those used currently in GB. This should give confidence that existing corrosion protections systems are most likely fit for purpose in a hydrogen transport scenario.

2 INTRODUCTION

Pipeline networks in Great Britain (GB) utilise a variety of corrosion protection techniques in order to protect their pipelines and other assets from damage. The first line of defence against external corrosion is the application of protective coatings and paints. The use of high-quality coatings limits corrosion to only two areas, microscopic points of missing coating known as holidays and areas of coating damage. On steel pipelines, cathodic protection (CP) is often used to offer protection to these uncoated areas.

There are two forms of CP used on pipelines, including both sacrificial cathodic protection (SCP) and Impressed Current Cathodic Protection (ICCP). SCP use a more reactive metal (such as magnesium or zinc) which acts as the anodic site and therefore corrodes instead of the steel pipeline. No external power source is required to run a SCP system, but the anodes will be consumed over time and will therefore need replacing periodically. ICCP systems use an external direct current (DC) power source to drive current from an inert, usually mixed metal oxide, anode to the steel. ICCP is more commonly used on the GB pipeline networks.

The diffusion of atomic hydrogen through steel is known to be possible and has been demonstrated in several laboratory-based experiments. Many factors are understood to affect the rate of hydrogen permeation, such as the microstructure and steel chemistry, the presence of residual stresses and existing damage such as scratches or gouges. Demonstrations such as the FutureGrid test program suggest that it is possible that hydrogen flux rates of up to 1.72×10^{-12} mol/cm^2.s through pipeline steel at 70 bar could be possible.

The GB gas industry is therefore interested to understand the potential impacts of hydrogen which has diffused through the steel pipeline on pipeline coatings and other forms of corrosion protection.

This project has undertaken a review of the relevant corrosion threats present on the pipelines and considered the potential influence of hydrogen on each mechanism. The probable effect of hydrogen at flux rates considered likely on the pipelines has also been discussed.

An exploratory test program has also been conducted to expose FBE, CTE, CALT and FBE+MCL coatings to representative levels of hydrogen flux for 7 weeks and determine whether there are any early signs of hydrogen related degradation.

DNV have also reviewed a number of National Gas Transmission (NGT) internal policies and procedures to identify potential changes that should be considered in the event of converting pipeline networks to hydrogen service.

3 POTENTIAL INTERACTIONS OF HYDROGEN AND RELEVANT CORROSION MECHANISMS

When considering the potentially relevant corrosion mechanisms present on the NTS, the following mechanisms have been identified as relevant to this work;

- General Attack Corrosion (External Corrosion)
- Pitting Corrosion
- Crevice Corrosion
- Corrosion under Insulation (CUI)
- Stress Corrosion Cracking
- AC Corrosion.

It is noted that Microbially Influenced Corrosion is also a threat to GB pipelines, but this mechanism has been investigated in other work and is therefore not included in this scope. To date, industrial research has mainly focused on the risks that hydrogen transportation poses to the bulk steel structure of the pipeline as it is well documented that hydrogen can cause deleterious changes to ductility related mechanical properties. In this project, the behaviour of hydrogen within steel structures is of interest for two reasons;

- Can the presence of hydrogen within the bulk steel affect the corrosion process, causing higher rates of corrosion?
- Can hydrogen which has diffused through the pipe wall have damaging interactions at the pipe surface, potentially effecting coating breakdown, coating adhesion or CP efficacy?

It is widely understood but important to note that it is not the hydrogen molecule (H_2) which is able to diffuse through steels, rather atomic hydrogen (H). Hydrogen atoms can be formed by a range of processes such as corrosion, cathodic protection, galvanic coupling, electroplating and by the dissociation of water vapour during welding. Hydrogen atoms may also be formed by dissociation of hydrogen gas on clean metal surfaces such as an active fatigue crack. Potential energy surface calculations have shown that the only stable state for molecular hydrogen on metal surfaces is dissociation to adsorbed atomic hydrogen /1/. Therefore, even at very low hydrogen pressures (<1 bar) a clean metal surface will be covered by adsorbed atomic hydrogen. Direct dissociation is inhibited by the presence of many other surface-active species, oxide films or coatings as it involves extremely close-range interactions allowing overlap between metal and hydrogen molecular orbitals.

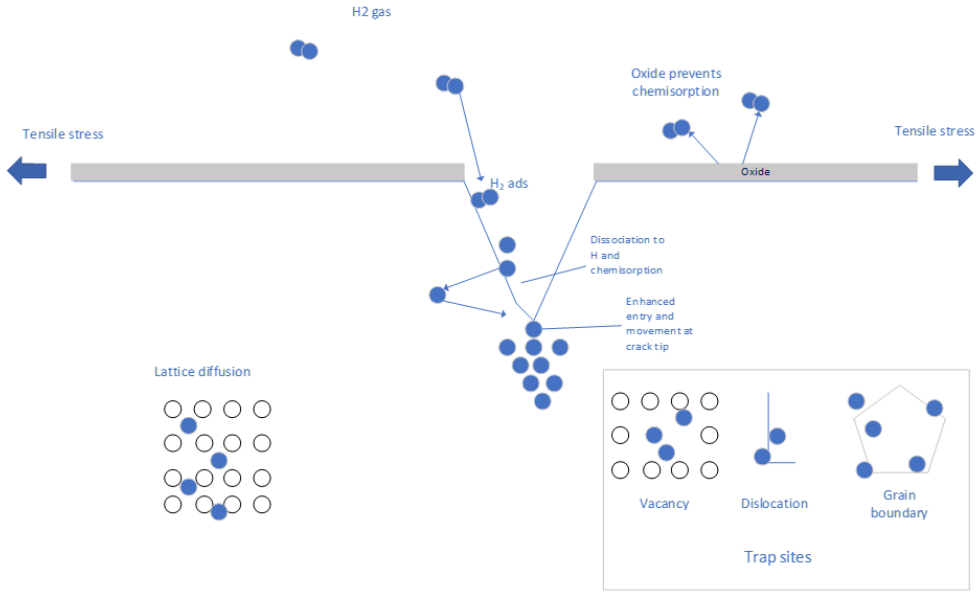

Figure 1 - Hydrogen and Steel Interactions

Hydrogen atoms then move through the bulk steel structure via diffusion, interacting and sometimes being "trapped" at various metallic features as shown in the figure above. However, once all trap sites are filled, hydrogen will move through the wall of the steel vessel and reach the external surface. Similarly, within the current hydrogen pipeline standards, it is considered that hydrogen will be present within steel and therefore its effects must be mitigated or controlled.

3.1 Interactions of hydrogen with the corrosion mechanisms

Now that the different corrosion mechanisms present on the NTS have been described, we can consider how the presence of hydrogen could interact with them to affect corrosion rates.

3.1.1 General Corrosion

In the context of hydrogen transport through pipelines, molecular hydrogen does not directly participate in corrosion reactions. On the contrary, the accumulation of H_2 gas on the metal surface, whether as a corrosion byproduct or present in the bulk gas, can block active sites and induce polarisation, which may slow down further corrosion.

This can also be seen from the Polarisation (Evan's) Diagram. On a polarisation curve (log current density vs. electrode potential), anodic curve is related to iron dissolution ($Fe \rightarrow Fe^{2+} + 2e^-$) and cathodic curve is related to hydrogen ion reduction ($2H^+ + 2e^- \rightarrow H_2$). The corrosion potential (E_{corr}) occurs where anodic and cathodic currents are equal. The corrosion current (i_{corr}) is proportional to the corrosion rate.

A higher H^+ concentration (lower pH) shifts the cathodic polarization curve upward (more cathodic current at the same potential). This is because H^+ reduction becomes easier and faster. The new intersection point with the anodic curve is at a higher corrosion current (i_{corr}) which means faster corrosion rate.

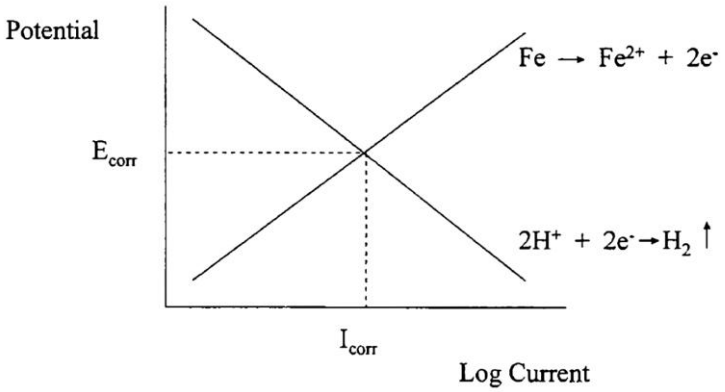

Figure 2 - Polarisation diagram of steel corrosion

However, introducing molecular H_2 does not affect the cathodic curve, as H_2 is already the reduced species. Instead, it can form a diffusion barrier on the metal surface, causing cathodic polarisation and potentially slightly decreasing the corrosion rate.

Hydrogen molecules are natural byproducts of corrosion reactions. Therefore, it is unlikely that unprotected metal on the network which is not subject to CP would be affected by additional hydrogen being present.

However, in areas where CP is present, the pipeline steel is being held at an artificial potential. The presence of small amounts of hydrogen is unlikely to affect the overall corrosion rate.

3.1.2 Pitting Corrosion

In pipelines, corrosion usually appears as localised pits rather than as a uniform thinning of the wall. This occurs because conditions at anodic sites tend to become more acidic: dissolved iron ions react with hydroxyl ions in water, leaving behind excess hydrogen ions. Meanwhile, at cathodic sites, hydroxyl ions are generated, creating a more alkaline and less corrosive environment.

As a result, once a pit initiates, corrosion activity becomes focused at that spot, causing the pit to deepen rather than spreading evenly. Pits may develop as isolated defects, or they can cluster and merge, leading to irregular but widespread wall thinning.

Pitting typically initiates at surface irregularities, such as inclusions or defects in a passive film or protective scale. Metals that rely on passive films for protection such as stainless steels and aluminium alloys are particularly vulnerable to this form of attack. Once a pit forms, the surrounding surface struggles to re-passivate, and the process often becomes autocatalytic. Because metal loss is concentrated at a small anodic site, the penetration rate in pitting corrosion can be very rapid.

In the case of pitting corrosion, dissolved hydrogen within the steel could facilitate the formation of new initiation sites, leading to secondary pit growth. This could lead to an increased rate of metal loss overall, it is unlikely to accelerate the rate of corrosion within a pit, as the bottom of the pit becomes the anodic site where hydrogen is a product of the reaction, rather than a reactant.

3.1.3 Crevice Corrosion

Crevice corrosion typically develops in areas where small volumes of stagnant electrolyte become trapped, such as between flanges, bolts, or nuts. Chloride ions strongly promote this form of attack. For crevice corrosion to occur, the gap must be wide enough to allow moisture ingress but narrow enough to retain the stagnant medium.

Oxygen depletion within the crevice polarises the cathodic reaction. Once passivity breaks down, the potential shifts in the active direction, sustaining localised corrosion. This process is autocatalytic, making crevice corrosion essentially a

specific form of pitting. It arises from oxygen concentration differences, where the crevice acts anodic to the more aerated exterior, it is also described as oxygen concentration cell corrosion.

The effect of hydrogen on crevice corrosion has been extensively researched via hydrogen charging testing on stainless steels and complex alloys. It was found that after hydrogen charging some stainless steels, that hydrogen can promote the initiation and propagation. The influence of hydrogen on crevice corrosion on the NTS is unknown as most of the testing to date focuses on stainless steels.

3.1.4 Corrosion Under Insulation (CUI)

Corrosion Under Insulation (CUI) is a severe form of localised external corrosion that occurs on insulated pipelines. Since it develops beneath the insulation, it is hidden from view, making detection difficult. CUI is a well-known and widespread industrial problem, referenced in standards such as NACE RP-01/98 /2/. To reduce susceptibility, pipelines are typically painted before insulation is applied.

CUI develops when water accumulates in the vapor or annular space between the insulation and the pipe surface, with sources including rainwater or leaks. This leads to localised wall loss. According to API 581, CUI is most common between −12 °C to 175 °C, with the most aggressive conditions occurring between 77 °C to 110 °C /3/. On GB transmission pipelines, operation temperatures are normally expected to be below 40 ºC, although higher temperatures are experienced downstream of compressors, for example. Factors influencing severity include rainfall, humidity, and chloride levels. High-risk sites include terminations at flanges, damaged insulation areas, and pipelines with deteriorated coatings or wrappings.

On above-ground carbon steel pipelines, CUI is primarily oxygen-driven. These systems are usually electrically isolated from underground sections, where cathodic protection (CP) systems are applied.

As the mechanism of CUI is similar to that of general corrosion, the influence of hydrogen on the rate of corrosion would be expected to be negligible as discussed above. However, it is also possible that hydrogen could influence the insulation material.

When corrosion first occurs on an insulated or coated pipeline, a holiday may allow hydrogen to escape easily, limiting permeation through the coating or insulation. However, as corrosion progresses and oxide layers form, hydrogen recombination and release become restricted, leading to buildup and increased permeation through the coating/insulation, up to the limit set by the steel's internal hydrogen concentration. However, insulation materials are generally low density and therefore highly permeable and are not expected to be affected by hydrogen.

3.1.5 Stress Corrosion Cracking (SCC)

Stress corrosion cracking (SCC) occurs when three conditions coincide: the presence of tensile stress, a susceptible alloy, and an environment that promotes cracking in that alloy. The tensile stress can be applied or residual, with welding-related residual stresses often being a contributing factor. Additional contributors may include hard spots, martensite in weld areas, coating defects, microbiological activity, or inadequate CP.

In underground environments, stress cracking of carbon steel pipelines has been reported, resulting from either anodic stress corrosion or hydrogen related mechanisms where the hydrogen has been generated by corrosion. This form of cracking is typically external and is not influenced by the hydrogen gas being transported within the pipeline.

SCC is fundamentally an electrochemical process involving both anodic and cathodic reactions. Corrosion specialists generally classify true SCC as being controlled by the anodic reaction, whereas cracking governed by the cathodic reaction is viewed as hydrogen embrittlement. Poorly applied cathodic protection can exacerbate this embrittlement mechanism.

3.1.5.1 Hydrogen-Induced Cracking (HIC)

Hydrogen-Induced Cracking (HIC) refers to stepwise internal cracks that link adjacent hydrogen blisters, either between different planes within the steel or extending to the metal surface. The formation of HIC does not require externally applied stress; instead, it is driven by high local stresses around hydrogen blisters, created by the internal pressure of accumulated hydrogen gas. When stress fields from multiple blisters interact, cracks can propagate and link them across different planes in the steel. The hydrogen that causes blistering originates from the corrosion reaction between the steel and wet hydrogen sulphide (H_2S).

The buildup of blister pressure is tied to hydrogen permeation through the steel, which is influenced by two main environmental factors: pH and H_2S content of the water. Hydrogen flux is typically lowest in near-neutral pH environments but increases at both lower and higher pH values. At low pH, corrosion is primarily caused by H_2S, while at high pH, the bisulfide ion drives corrosion. Elevated H_2S levels—such as 50 ppm in water—are sufficient to trigger HIC.

The steel's susceptibility to blistering and HIC is therefore closely tied to its quality, particularly the sulphur content, as lower sulphur reduces risk. Additions of calcium or rare earth metals (REMs) that refine sulphide inclusions are also beneficial.

Although blistering alone does not normally create a leak path, it becomes critical if it develops near welds, where residual stresses can drive cracks to the surface. This condition represents the most severe case of HIC/SOHIC in H_2S environments.

Sulfide Stress-Oriented Hydrogen-Induced Cracking (SOHIC) is a special form of HIC, consisting of stacked arrays of blisters connected by cracks aligned through the steel thickness. SOHIC typically occurs in the base material near the heat-affected zone (HAZ) of welds, where high localized tensile stresses arise from both applied loading (e.g., internal pressure) and welding residual stresses. As with HIC, plate steel quality strongly influences susceptibility. Post-weld heat treatment (PWHT) can help reduce residual stresses and therefore the severity of SOHIC, although it may not completely prevent it. The level of applied stress also plays a significant role in SOHIC development. While more common in plate steel fabrications, HIC/SOHIC has also been observed in pipe steels under severe hydrogen-charging conditions.

However, the hydrogen flux produced by charging by corrosion in wet sour gas is orders of magnitude larger than that from charging the steel in dry hydrogen gas. HIC requires hydrogen gas to accumulate around metallurgical defects such as inclusions and in hydrogen gas insufficient flux would be present to allow this accumulation in practical timescales. Thus, HIC in hydrogen gas pipelines is not regarded as a credible threat.

3.1.5.2 Near Neutral pH Stress Corrosion Cracking

Transgranular SCC (commonly known as near-neutral SCC) first became a concern to the pipeline industry after a series of failures in the Canadian transmission networks starting in the mid-1980's. It is distinct from better known intergranular SCC mechanism in that the transgranular SCC failures are associated with bicarbonate containing waters with near-neutral pH (~7) whereas the intergranular failures are associated with a concentrated bicarbonate-carbonate solution with pH>9.3 [18]. Two mechanisms have been proposed for near-neutral SCC, one based on anodic dissolution and one on hydrogen assisted cracking. The hydrogen mechanism has gained general acceptance due to evidence such as the quasi-cleavage fracture surfaces containing secondary cracking. Colwell and Leis [19] have suggested a mechanism where hydrogen is produced by the aqueous environment containing CO_2 as shown below:

$$H_2CO_3 = HCO_3^- + H^+$$

$$HCO_3^- = CO_3^{2-} + H^+$$

This mechanism explains the iron carbonate observed in regions of cracking and the hydrogen formed can enter the steel and assist in the cracking mechanism. Some workers have suggested that the hydrogen increases the rate of anodic dissolution, but more recent results have cast doubt upon this explanation [20].

Thus, the relevant conclusion from the research is that hydrogen will already be present in the crack region even without any charging from internal hydrogen pressure.

Atomic hydrogen can be produced by corrosion or cathodic polarisation (e.g., from cathodic protection systems) which can generate adsorbed atomic hydrogen on the metal surface. If the hydrogen is dry, then internal corrosion would not generate hydrogen so corrosion related hydrogen would be found only at the external surface as would hydrogen from the cathodic protection system. Hydrogen at the external surface would not increase the risk from near-neutral SCC cracks as it is also present in the natural gas case.

For the hydrogen diffusing through the steel to increase the severity of near-neutral stress corrosion cracks it would need to increase the hydrogen concentration in the near crack region above that already present from aqueous charging as described above. Modelling has shown that an enhanced hydrogen concentration already exists ahead of the crack tip and that the presence of near-neutral cracks indicates that anodic dissolution and thus hydrogen charging from the external surface has already occurred. Hydrogen charging by external corrosion is considerably more effective than gaseous charging and thus the resulting hydrogen concentrations should exceed those generated by hydrogen inside the pipe.

Thus, as external charging is more effective than internal charging and the concentration from external charging (or the cracking mechanism) can be enhanced ahead of the crack tip it is extremely improbable that the presence of hydrogen inside the pipe would increase hydrogen concentrations at the near crack tip as the concentrations at the crack tip would already be higher than those in the bulk produced by internal charging. Thus, the presence of hydrogen inside the pipe would not increase the severity of near-neutral cracking.

3.1.6 AC Corrosion

AC (alternating current) corrosion occurs when the AC from nearby powerlines interfere with buried, cathodically protected steel pipelines. AC corrosion is a damage mechanism found when pipelines run parallel to high voltage (HV) AC electricity transmission powerlines. These HV AC powerlines often run in corridors where multiple powerlines all run in close proximity, increasing the risk to buried pipelines and creating condition which allow AC to couple onto the bare pipe surface. AC corrosion is a risk to uncoated pipelines or locations in which the coating has deteriorated such as holidays.

Hydrogen does not alter the electrochemical mechanism that causes AC corrosion. The smooth defect associated with AC corrosion, results in a lower stress concentrator, reducing the driving force for hydrogen diffusion into the steel, reducing the likelihood of hydrogen related cracking. While these smooth defects are therefore less susceptible to hydrogen assisted damage mechanisms, the tolerance for wall loss may be reduced, making AC mitigation plans, high coating quality and maintained CP systems essential.

4 POTENTIAL INTERACTIONS OF HYDROGEN AND CORROSION PROTECTION

Pipelines are protected from the environment by use of a corrosion protection system. For above ground pipework and components, this corrosion protection comprises primarily of paint. For buried pipelines, high pressure pipelines are protected from external corrosion by a coating and, where applicable, a CP system. Other corrosion protection systems (or systems which locally replace other corrosion protection systems) are also present in the form of repairs, sleeves and other types of encapsulations such as grouted tees.

4.1 Potential interactions of hydrogen with coatings

Pipes which are purchased for pipeline construction are commonly supplied with a factory applied coating. FBE is now the most used coating whereas historically, CTE was also widely used and is therefore still prevalent on the NTS.

Field applied coatings are also used to cover uncoated areas of pipe, such as girth welds or areas of other damage. These include CALTs and MCL. Cold applied self-adhesive overwrap tapes and grease/wax-based tapes are also used. Brushing mastics are only used to repair pipelines where they have previously been used. Shrinkable materials are used, but rarely. Fillers are only used in conjunction with tapes, to smooth the profile of the component being wrapped to allow for a more successful application.

The following polymer types to be identified as in use on GB pipeline networks.

Table 1 - Simplified list of materials used in pipeline coatings

Coating "Types"	Material Combinations
Urethane based coatings	Polyurethane
	Urethane
	Urethane mastic
	Polyester & Aliphatic Polyurethane
Bitumen/Rubber and backing tape	Rubber modified bitumen & Fabric backing
	Rubber modified bitumen & Poly-vinyl Chloride (PVC) backing
	Rubberised bitumen & geotextile fabric
	Polymer modified bitumen & PVC backing
	Bituminous rubber & PVC backing
	Polyethylene Film & Rubber Based Adhesive
Epoxy based	Epoxy
	Epoxy Resin
	Thermosetting Epoxies
Petrolatum and Wax based	Synthetic fibre fabric & Petrolatum compound
	Wax based tape & Paste (unspecified)
	Petrolatum compounds
PVC Tape	PVC Tape
Polyethylene	High Density Polyethylene
Mastics	Mastic adhesive

Hydrogen can conceivably disrupt coatings in multiple ways. Firstly, the hydrogen atoms could disrupt the chemistry of the coating. This could lead to general degradation of the material, which would expose more of the surface to the environment, leading to more potential for corrosion. Both atomic hydrogen and H_2 are small molecules which can diffuse through materials with low density, and studies have shown that hydrogen has the highest diffusion co-efficient

through polymers when compared to other common process gasses (CO_2, N_2, CH_4 and O_2)/4/. There are documented embrittlement effects which are noted in certain polymers (nitrile rubber, for example).

Current hydrogen standards do offer guidance on the compatibility of certain polymers for hydrogen service, and this is shown in Appendix B. The IGE/TD/1 supplement also offers a list of polymers that are suitable for service at under 2 bar pressure /6/. It is important to note that the coatings, while they could be exposed to hydrogen, will not be exposed to line pressure, only the small amounts of hydrogen which permeate the pipe. Analysis has allowed for a high-level identification of the types of polymer present in GB pipeline coatings. Many of these are considered acceptable for hydrogen service as per the table in Appendix B summarising the guidance of ISO 11114-2, ISO 15916 and the EIGA guidance /7//8//9/.

The degradation of the coating could also lead to a reduction in adhesion, leading to coating disbondment. This mechanism can be compared to the postulated mechanisms which cause coating disbondment from over-polarisation of a CP system. This is believed to be a complex combination of mechanisms, where at least part of the disbondment is caused by the hydrolysis of the chemical bonds between the coating and the pipe surface, which is often covered with metal oxides/hydroxides on the passivated metal/10/. The introduction of additional hydrogen at the surface could increase the rate of hydrolysis, leading to higher rates of coating disbondment and higher corrosion rates.

It is also possible that if hydrogen atoms reach the external pipe surface and recombine into H_2 a faster rate than it is able to diffuse through the coating to escape to atmosphere then this could lead to coating disbondment and blistering.

PRCI investigated the effect of hydrogen on external coatings in the context of the coating of welds, which outgas hydrogen post construction /11/. The results showed that out of FBE and liquid epoxy coatings, the FBE seemed resistant to blistering whereas the liquid epoxy did blister. Therefore, to predict the behaviour of the coatings, it is important to have a realistic measure of the possible rate of hydrogen diffusion through the pipe wall, to see whether these results are relevant for normal pipeline operational pressures.

4.2 Potential interactions of hydrogen with paints

Paint is used to protect above ground pipework and equipment from the environment. Paint performance specification classes consider the material to which the paint is to be applied, the environmental conditions and the temperature range.

Paint will be qualified for service by defining both essential and desirable parameters. These parameters include water resistance, UV resistance, chemical resistance, adhesion and age resistance. When considering the materials used in paints, it is often not possible to be specific as the compositional information is proprietary to the manufacturer. However, in general paints comprise of pigments and solvents, with the addition of binders to keep the mixture emulsified and then other additives to improve performance. The binders can often be acrylic, vinyl or epoxy based.

When considering the effect of hydrogen on paints, ultimately the possible effects are the same as for coatings. The main differences for paints are that paints are generally applied in thinner layers than coatings, offering a less substantial barrier to diffusion of hydrogen away from the pipe surface.

UV breaks down paint systems by breaking down chemical bonds and forming reactive free radicals, which go on to further damage the paints' molecular structure. Atomic hydrogen is a free radical. Therefore, it is possible that paints with a higher UV resistance are less susceptible to damage from permeating hydrogen.

As with coatings, to determine the risk profile to paints on the network, it will be necessary to accurately characterise realistic rates of hydrogen permeation through pipelines.

4.3 Potential interactions of hydrogen with CP

Cathodic protection (CP) is a method used to minimise the deterioration due to corrosion on buried pipelines; it reverses the natural electrical current flow between anodes and cathodes that occurs during the corrosion process. As a result the entire protected structure becomes a cathode. CP is achieved by connecting an external anode to the metal that requires protection and allowing a direct current to run from the introduced anode to the metal (which becomes the cathode) at a sufficient level to minimise the corrosion process.

There are two major types of CP systems, sacrificial cathodic protection (SCP) and impressed current cathodic protection (ICCP) systems. SCP systems use a reactive metal or alloy, most commonly magnesium for buried pipelines, as an anode that are then connected to the metal being protected, this causes a shift in the electrical potential of the pipe, and it becomes the cathode. ICCP systems consist of an external power source driving the CP current. Unlike SCP, the anode does not directly contact the pipeline requiring protection, but rather in an ICCP system it is connected to the positive side of a DC power supply, and the pipeline is connected to the negative side of the power supply. Both ICCP and SCP systems are traditionally used with a coating system to control the current demands.

A range of environmental and operational factors influence CP performance, including:

- **Soil resistivity:** the lower the soil resistance the easier the current will flow and the more efficient the system, the higher the resistance the greater the driving voltage required, and the more anodes required.
- **Coating quality:** a good coating reduces the current demand, whereas an increased number of defects or areas of exposed steel increase the system load.
- **Pipeline proximity to other buried structures:** If the pipeline is close to other metallic structures, not connected to the CP system, or other sources of electrical interference such as overhead powerlines.
- **Seasonal variations:** Increased water content in soil can lower the resistivity in soil and increase the conductivity improving the throw of current from the CP system.

CP in the UK for buried pipelines is governed by a set of well-defined British and International standards, supported by National Gas policy documents which translate the standard requirements into asset specific practices. The main standards used in the UK for CP include BS EN ISO 13509:2003 and 15589-1:2017 which both similarly specify the requirements and recommendations for pre-installation surveys, design, installation, commissioning, operation, inspection and maintenance for onshore pipelines/12//13/. Additionally, BS EN 12954:2019, which details the implementation and management of a CP system for buried structures /14/. National Gas' policies documents translate the broader British standards into asset-specific, implementable requirements and guidance for the NTS.

Network policies include important criteria for ensuring a functional and effective CP system. This includes the mandatory use of the minimum protection criteria of -850 mV instant off (IOff) vs a $Cu/CuSO_4$ reference electrode. Additionally, for the design of ICCP systems it details the minimum separation distance between anodes and the pipeline, the groundbed design requirements as well as general design such as cable sizing, insulation type and routing. For maintenance it details the survey requirements, intervals and techniques and test post requirements and tests. The use of these policies allows effective corrosion mitigation through the use of a CP system.

The transportation of hydrogen introduces additional considerations with regards to the external CP system, particularly when evaluating its operational performance for continued efficiency. Although the internal environment is separated from the external steel-soil interface where the CP is operational, hydrogen may still influence how the CP system operates.

The thresholds for CP are currently defined with the minimum protection criteria set at -850 mV (or -950 mV for areas with suspected sulfate reducing bacteria) vs a $Cu/CuSO_4$ reference electrode. This value is ultimately determined by the rest potential of steel, which will be unchanged in hydrogen service. It further details that an overprotection criterion of -1150 mV vs a Cu/CuSO4 reference electrode. If the IOff potential was go lower (more negative) than this value for

prolonged periods of time, coating disbondment is known to occur due to electrochemical charging and hydrogen evolution is possible even in natural gas pipelines. Therefore, it is conceivable that the addition of hydrogen diffusing through the metal could add to this mechanism and lead to detrimental effects being seen with less negative polarities applied by the CP system. If this effect was proven to have a measurable effect on the CP system, then the overprotection criteria would need to be reconsidered.

Additionally, the formation of hydrogen bubbles at the steel surface can lead to fluctuations in the measured potential due to disruptions in the local electrochemical environment. This effect is probably too localised to affect the control of a CP system. In addition, the presence of hydrogen evolution at high rates can make the system more susceptible to potential fluctuations caused by external alternating or direct stray currents, as the overall system impedance and reaction kinetics are altered.

During the installation of an ICCP system, the method of pin brazing is often used as an attachment method to connect CP cables and earthing bonds to steel pipes. It is used as an alternative to welding as it has a controlled low-heat input into the steel pipe, reducing the thermal loads that be seen with welding. The process uses a short duration electrical arc to melt a silver-based brazing alloy, creating a reliable metallurgical bond while keeping the heat affected zone (HAZ) small and controlled. As the thermal input is low and over a short period of time, the process of pin brazing does not typically result in localised high hardness areas or significant microstructural changes that may make the steel more susceptible to hydrogen-related cracking (or other damage mechanisms), it is therefore not considered a significant risk to a pipeline. Despite this, the thickness of the steel should be controlled carefully, for hydrogen service, to ensure that if any localised areas of microstructural change do occur, there is significant wall thickness of the original and expected microstructure remaining to maintain the pipe wall integrity.

Overall, it is assumed that the interaction between hydrogen and a CP system is minimal, and hydrogen specific standards, such as ASME B31.12 detail the CP requirements under hydrogen service /15/. ASME B31.12 does not introduce any new or different CP requirements for hydrogen pipelines compared to natural gas pipelines. It details the same CP criteria, design rules and monitoring requirements. Based on the above, and despite no change to the ASME standard, it may be deemed appropriate in the future to apply stricter controls for over-protection to minimise the risk of coating disbondment however, the extent to which this may be an issue is unknown at this time.

4.4 Interactions of hydrogen with repairs and sleeves

When considering scenarios where the presence of hydrogen on the external surface may lead to a change in the corrosion protection of the pipeline, repairs and sleeves must also be considered.

The types of repairs which can be made on a pipeline operating at above 2 bar can be summarised as:

- Material removal (dressing)
- Metallic deposition (weld deposition)
- Pipe replacement
- Welded on shells (including hot tap tees, snug fitting shells and stand-up shells)
- Epoxy shells (where epoxy resin is used to bond a steel shell to the pipeline)

NGT also has many pipeline sections which are sleeved. Sleeves are used for several reasons, but essentially the purpose of sleeves is to provide additional protection to the pipeline for those crossing traffic routes, and to provide pressure containment in the event of a failure.

During the early 1960’s sleeves were typically air filled with the ends sealed to prevent the ingress of soil and groundwater. Towards the end of the 1960’s and early 70’s the annular space between the sleeve and carrier pipe was

filled with cementitious grouts, or thixotropic materials such as bentonite. The cementitious and bentonite fillers provided an electrical path to help facilitate the flow of CP current through the sleeve to protect the carrier pipe within the sleeve.

During the 1970's, on new pipelines, steel sleeves were modified to incorporate a nitrogen fill, which would provide an inert, non-corrosive atmosphere; these were considered to be an improvement over sleeves containing the annular fills such as cement and bentonite.

Current recommendations for sleeve design are given in IGEM/TD/1, which states that operators should prioritise grouted concrete pipe as the preferred method for sleeves, steel sleeves can be used /6/. For the grout, cementitious grout is recommended; however other materials are allowed as long as the either inhibit corrosion or allow cathodic protection to reach the carrier pipe (cement or alkaline grout).

There are two major ways in which conceivably permeating hydrogen could affect repairs and sleeves with regards to corrosion control. Firstly, could the hydrogen disrupt the bonding between the repair or sleeve and the pipe, and therefore expose the pipe surface to the environment, potentially raising corrosion rates. Secondly, could the repair or sleeve capture enough hydrogen to create a situation where the repair or sleeve fails, but this is considered outside the scope of this work.

ASME B31.12 GR-5.5 provides guidance on the types of repair techniques that can be applied to pipelines operating in hydrogen service /15/. Welded repairs are permitted, and for the purposes of this report would be considered the same as replacing a pipe section, with no additional corrosion risk. The main risk presented is in the case of shells and tees etc is if the presence of permeating hydrogen can disrupt the material being used to fill the void between the shell and the pipe. This could be most consequential in cases like a grouted tee. While the tee itself is constructed from steel, the grout acts to bind the shell to the pipeline, primarily to transfer the load from the tee to the pipeline. As discussed in Section 4, it has been found that epoxy-based materials can blister in the presence of permeating hydrogen.

The tee is sealed both against the internal gas pressure and water ingress using hydrogenated nitrile butadiene rubber (HNBR) which has been reported as compatible with hydrogen service /15/. If permeating hydrogen disrupted the bonding or mechanical integrity of the grout, this could lead to either water reaching the surface of the pipe, or a pressure leak but only if the HNBR seals also failed. Tees are commonly installed in areas with complex system loads and the grout is vital in supporting the gas-tight seal and the mechanical integrity of the tee. It is therefore considered likely that if hydrogen were to cause significant levels of disbondment, this would negatively affect the integrity of the tee.

In the case of concrete and other grouted sleeves, the main role of the grout is to ensure that the pipeline is protected from water ingress into the sleeve annulus and to support the loading experienced by the steel shell. Disruption of the interface between the buried pipeline and the grout would not affect the ability of the epoxy to transmit load. However, disbondment could allow water to access the pipe/grout interface causing general corrosion of the surface.

5 Test Program and Results

To investigate the potential impact of hydrogen diffusion on NTS coatings, NG commissioned the testing of four ex-service pipe samples. DNV developed a test program which used electrochemical charging to simulate a high hydrogen environment and then use a range of techniques to determent whether any breakdown of the coating could be detected.

The ex-service pipe samples had the following coatings:

Table 2 - Coating Identification

Coating Description	Coating Code	Year of Application (approx.)
Coal Tar Enamel	CTE	1973
Cold Applied Laminate Tape	CALT	1969
Fusion Bonded Epoxy with Multi-Component Liquid	FBE+MCL	1979
Fusion Bonded Epoxy	FBE	1998

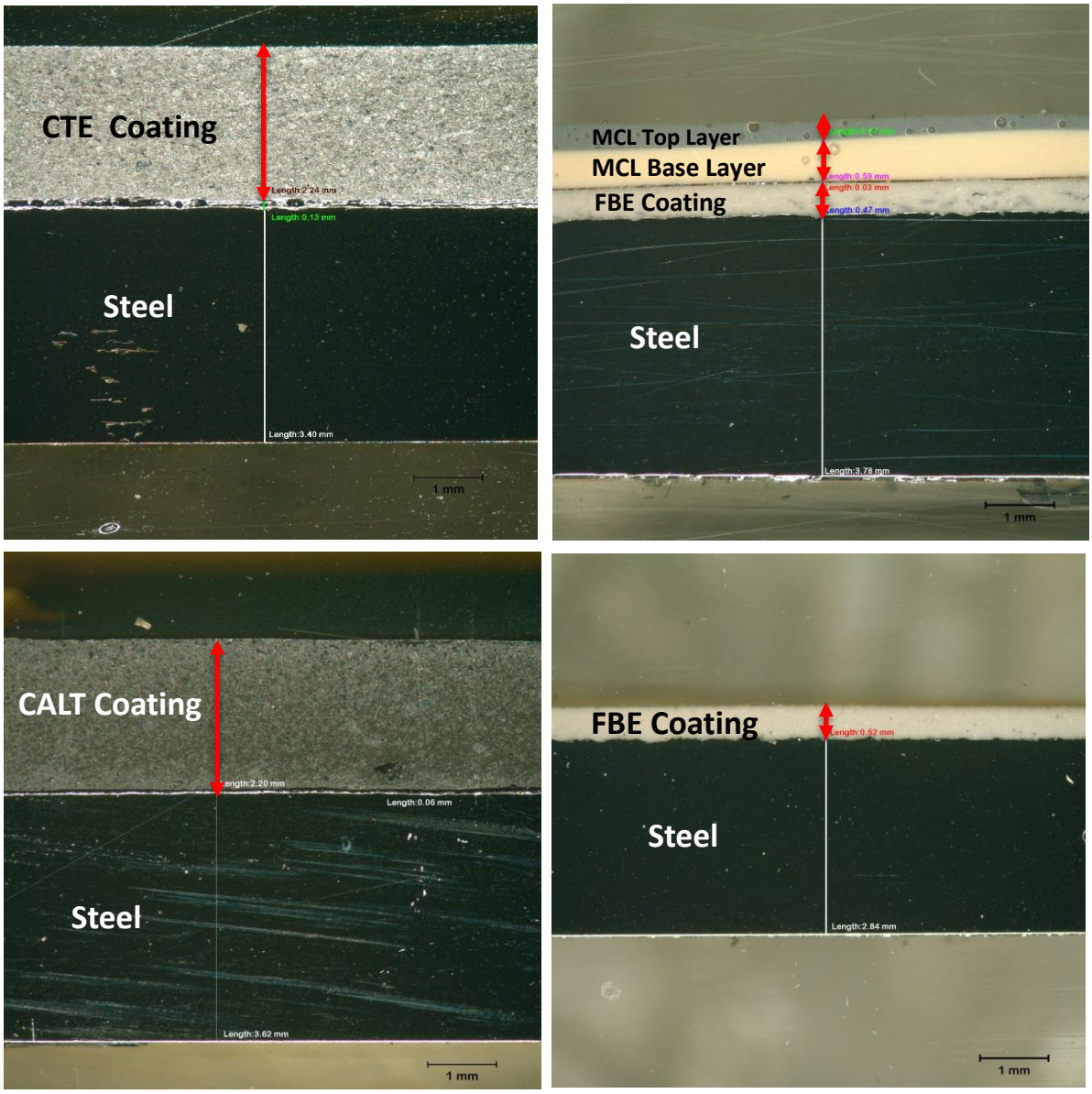

Figure 3 - Coating Cross-sections

Three different types of samples were extracted from the materials provided by NG. The description and dimensions are listed below:

- Control samples: Square samples of 69.9 mm (2.75 in) x 69.9 mm (2.75 in) extracted from CALT, CTE, FBE+MCL and FBE. The thickness was intended to account for the preservation of the coating and 3 mm of bare metal facing the ID. These samples were used as a 'control', i.e., samples were not exposed to conditions that could result in hydrogen charging.
- H_2 charged samples - Electrochemical: Square samples of 45.7 mm (1.80 in) x 45.7 mm (1.8 in) extracted from CALT, CTE, FBE+MCL and FBE. The thickness was intended to account for the preservation of the coating and 3 mm of bare metal facing the ID. These samples were subjected to environmental conditions where they could be charged with hydrogen as a result of exposure to an aqueous environment and applied current density.
- H_2 charged samples high pressure: After initial measurements, FBE was selected to be evaluated in hydrogen charging conditions as a result of exposure to 70 bar H_2. Samples were discs of approximately 25.4 mm (1 in) of diameter and thickness adjusted to preserve the coating and 3 mm of bare metal.

5.1 Experimental design

5.1.1 Control

CALT, CTE, FBE and FBE+MCL control samples were evaluated by exposure to NS4 solution and using a Gamry coatings cell as shown in Figure 3. The setup is based on cylindrical glass cell clamped to the sample. For this program, the electrical connection to the samples was made by using copper tape. The cells were filled with NS4 solution and deaerated through periods of 7 days, after which EIS measurements were conducted to evaluate the performance of the coatings. The solution was refreshed after each measurement to avoid any significant chemistry changes. It is worth noting that during initial measurements, the EIS measurements were challenged by the high resistance of each of the coatings tested. In order to obtain reasonable impedance values, representative of defective coatings, a hole of approximately 2 mm was drilled on the samples and through the coating to expose the bare metal. This defect size was chosen as it was large enough to be repeatable and for the bottom of the defect to be cleaned to expose a consistent amount of bare steel, whilst still providing a large surface area of attached coating

Under this configuration, the electrolyte could reach the underlying metal, enhance any electrochemical measurements and serve as focal point to assess any coating damage. The values obtained from these tests were used as a baseline to assess any changes due to hydrogen exposure. After extracting from the coatings cell, the samples were subjected to pull off tests.

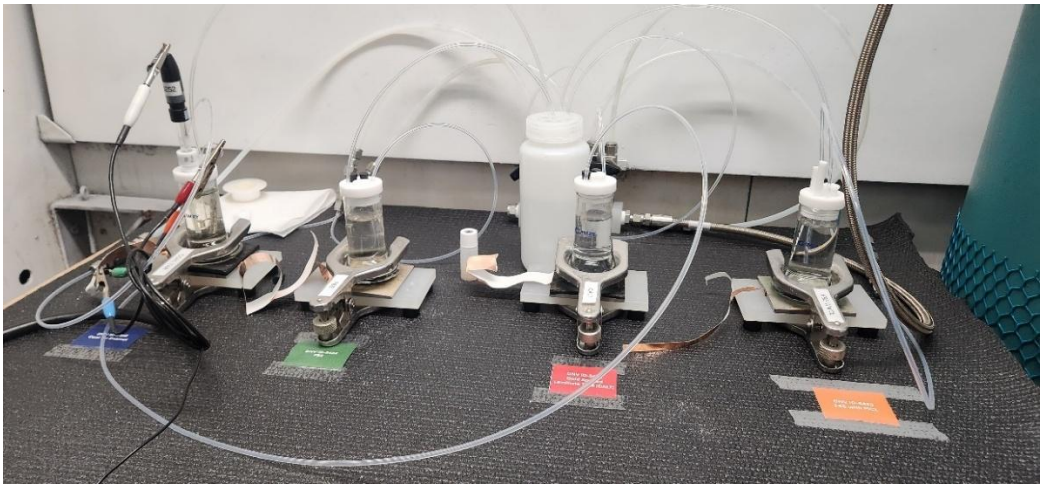

Figure 4 – Experimental setup to evaluate the performance of coating under no hydrogen charging conditions.

5.1.2 Hydrogen Permeation Set-Up

ASTM G-148 offers a standard procedure for the evaluation of hydrogen uptake, permeation and transport in metals using an electrochemical technique /16/. This uses a technique developed by Devanathan and Stachurski, which requires separate charging and oxidation cells between which a specimen of material can be affixed. The charging cell can be either gaseous or aqueous. The experimental setups used for this programme are shown in Figure 3.

An initial stage of this programme considered both gaseous and electrochemical charging of X52 carbon steel without any coating. This proof of concept was based on the following:

- High pressure test: A modified Devanathan cell was used in which the charging side was replaced by a C-276 autoclave capable of containing pressures as high as 200 bar (3000 psi). The surface of X52 carbon steel discs (25.4 mm of diameter and 3 mm of thickness) was prepared by grinding the side exposed to charging using silicon carbide paper 600 grit. The side exposed to the oxidation side was subject to an electroless nickel plating procedure to deposit a nickel film that would assist hydrogen detection. Previous to hydrogen charging, the autoclave was subjected to a pressure test using 110 bar of high purity N_2. Subsequently, and upon no leaks detected, the autoclave was subjected to a preconditioning procedure aimed to reduce humidity and oxygen. After reaching <1 ppm O_2 and <5ppm H_2O, the pressure of the autoclave was raised to 70 bar using high purity H_2. The oxidation side contained 0.1M NaOH and remained at 0V Hg/HgO throughout the test. A series of transient (hydrogen charged) and decay (hydrogen released) cycles were conducted to assess the hydrogen flux (J_{ss}) under high pressure.
- Aqueous H_2 charging: After confirming Jss, a series of experiments in aqueous environments were conducted to establish the parameters (Eapp or iapp) to safely simulate the gaseous condition. The surface of the sample was prepared as explained for the high-pressure test. The setup was based on two glass cells for the charging and the oxidation sides. The charging side contained 3.5% NaCl and several E and i values were evaluated. The oxidation side oxidation side contained 0.1M NaOH and remained at 0V Hg/HgO throughout the test.

CALT, CTE, FBE and FBE+MCL performance under hydrogen charging conditions was evaluated using the setup described for aqueous charging. The charging side was similar to described previously for aqueous charging. However, the solution on the oxidation side was replaced with NS4 solution which is an electrolyte meant to simulate neutral soils. Instead of holding E, this side of the setup remained at open circuit potential. After periods of 7 d, the current on the charging side was interrupted and the cell was drained. This step was intended to stop the hydrogen flux through the sample and prevent any corrosion that could alter the surface and affect the hydrogen permeation. Additionally, this step would favour the measurements on the oxidation side pertinent to the coating performance. EIS was performed on the oxidation side from 100000Hz to 0.1 Hz, 20 mV and 10 points per decade. After each measurement, the NS4 solution was drained and refreshed along with the solution on the charging side. Finally, the charging conditions were resumed.

To validate the hydrogen permeation rates and effects on the coatings observed in the aqueous cells, one FBE coated sample was also tested using a gaseous charging cell pressurised to 70 barg.

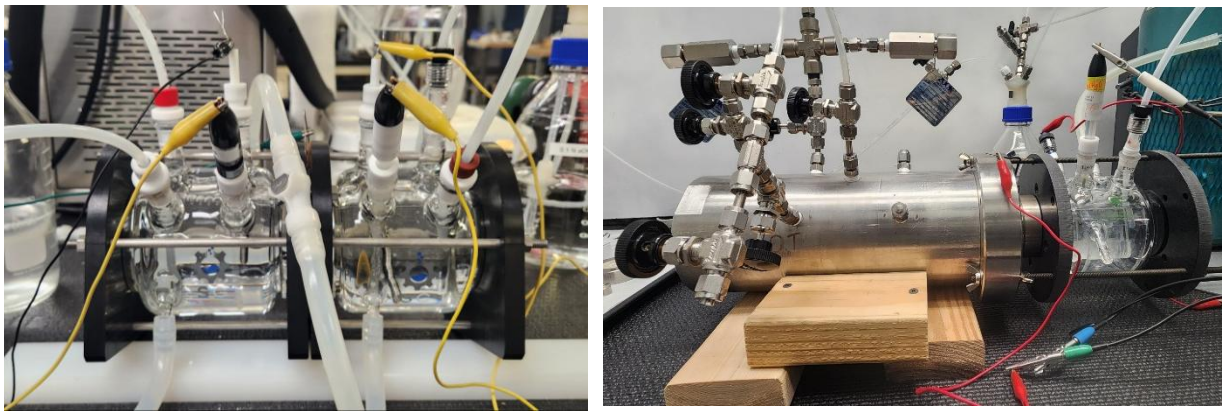

Figure 5 - Left, aqueous charging and oxidation cells. Right, gaseous charging cell with aqueous oxidation cell

5.1.3 Post-exposure testing

Once the 7-week exposure period was over, the samples were subject to both non-destructive and destructive analysis such that any differences between the control and hydrogen exposed samples could be identified.

5.1.3.1 Visual Inspection

After exposure to either control or hydrogen charging conditions, the samples were removed from the experimental setup, cleaned with de-ionised water and dried with compressed nitrogen. Subsequently, samples were visually inspected to assess any signs of corrosion around the induced defect and discolouration, delamination and/or blistering of the coating. The pictures were acquired by using a Keyence VHX-X1 advanced digital microscope system designed for high-resolution surface inspection, failure analysis, and materials characterization. It combines optical microscopy with real-time digital image processing to deliver high-magnification (up to ~2000×), high-depth-of-field imaging without complex sample preparation.

5.1.3.2 Pull off Adhesion Test

The pull-off adhesion tests of CALT, DTE, FBE and FBE+MCL were performed in accordance with ASTM D4541 to determine the tensile adhesion strength of the applied coating system. The method evaluated the force required to separate a bonded aluminium loading fixture (dolly) from the coated substrate by applying a tensile load perpendicular to the surface. Both the maximum pull-off strength and the mode of failure were used to assess coating adhesion performance.

Prior to testing, representative areas of the coated surface were selected while avoiding edges and visible defects. The coating surface and the faces of the loading fixtures were cleaned to remove dust, grease, and contaminants that could interfere with adhesive bonding. Test locations were marked to allow sufficient spacing between measurements and to prevent interaction between adjacent test areas.

The dollies were bonded to the coating surface using 3M 460 liquid epoxy. An uniform adhesive layer was applied to the dolly face, and the dolly was pressed firmly against the coating to ensure full contact and proper alignment normal to the surface. Excess adhesive was carefully removed from the perimeter of the dolly prior to curing. The adhesive was allowed to cure fully overnight.

The coating was cut around the perimeter of the dolly down to the substrate using an appropriate cutting tool. This step isolated the test area and minimized the influence of lateral stresses in thick or high-strength coatings. Whether circumferential cutting was performed was recorded, as it can influence the measured pull-off values.

Following adhesive curing, the pull-off adhesion tester (Positest) was attached to the dolly and aligned to ensure that the applied load was perpendicular to the coating surface. Tensile load was applied at a controlled and steady rate. Loading continued until failure occurred, and the maximum force or pressure at the point of detachment was recorded.

The pull-off adhesion strength was calculated by dividing the maximum applied force by the dolly surface area and was reported in units of megapascals (MPa) or pounds per square inch (psi). After testing, both the detached dolly and the exposed surface were visually examined to determine the mode of failure. Failure was classified as adhesive failure at the coating–substrate interface, cohesive failure within the coating, cohesive failure within the adhesive, or substrate failure.

A minimum of two replicate measurements were conducted for the control and hydrogen charged conditions. Additionally, As-received samples of each of the coatings were also tested using this method.

5.1.3.3 Cross Section Analysis

As mentioned before, the area where the induced defect was located was left intact during the pull off test. This was intended to subsequently cut the sample and study the cross section of both control and hydrogen charged samples. After cutting, the samples were mounted without using any external heat that could compromise the integrity of the coatings. The samples were polished up to 3µm using a combination of silicon carbide paper and diamond paste. Picture of the cross sections were acquired using a Keyence VHX-X1 digital microscope.

5.2 Test Program Results

All the samples were run for a minimum of 7 weeks exposure time, with the system drained to allow for EIS measurements taken every 7 days. At the end of the exposure time, the samples were removed from either the Gamry cell or the modified Devanathan-Strarchurski cell and dried using compressed nitrogen. The findings are summarised below.

5.2.1 CALT Sample

Figure 6 presents the evolution of the low-frequency impedance magnitude, $Z_{0.01Hz}$, of a cold-applied laminate tape (CALT) coating as a function of exposure time. The data are divided into a control sample exposed to a simulated soil solution (NS4, pH 7.4) without hydrogen charging, and a sample subjected to hydrogen charging under cathodic polarization on the bare metal side and the coated sample exposed to NS4 solution. It is important to mention that artificial defects were created on the surface of the samples by drilling 2 mm holes. The impedance measured at 0.01 Hz is commonly used as a key indicator of coating protective performance, as it reflects long-term processes such as ionic transport through coating defects, water uptake, and electrochemical activity at the coating/metal interface. Higher values of $Z_{0.01Hz}$ generally indicate a more resistive system with improved barrier properties, whereas lower values suggest increased electrolyte access and under-film corrosion activity.

The control sample exhibits relatively low impedance values throughout the exposure period, increasing modestly from approximately 20 kΩ at early exposure times to around 70–80 kΩ after extended immersion. This behavior indicates that, while the coating does not experience rapid failure, it allows significant ionic transport through pores, seams, or interfacial pathways, such as the induced defect, enabling ongoing electrochemical interactions at the substrate surface. The gradual increase in impedance with time may be attributed to partial pore blocking by corrosion products, deposition of solids at the interface, or general stabilization of the coating/electrolyte system after initial wetting.

In contrast, the hydrogen-charged sample display markedly higher impedance values at all exposure times, ranging from approximately 140 kΩ up to 300–330 kΩ. The impedance increases significantly during the early stages of exposure, reaching a maximum around 672 hours, and remains elevated thereafter. The consistently higher low-frequency impedance demonstrates that the electrochemical resistance of the system under hydrogen charging and cathodic polarization is substantially greater than that of the control condition. This could be related to possible reduced ionic conduction and suppressed interfacial electrochemical activity. Additionally, the hydrogen flux could result in bubble formation in the defect and add up to the overall resistance. The formation of interfacial deposits or precipitates

can block coating defects and transport pathways. These processes effectively reduce ionic mobility and contribute to higher low-frequency impedance values, even if the intrinsic properties of the polymeric coating remain unchanged. The differences between $Z_{0.01Hz}$ values reflect enhanced electrochemical resistance under hydrogen charging conditions; however, they do not necessarily imply the absence of hydrogen-related degradation mechanisms. Phenomena such as loss of adhesion, cathodic disbondment, or localized blistering may not be fully captured by impedance magnitude alone and were evaluated using complementary mechanical and visual assessment techniques.

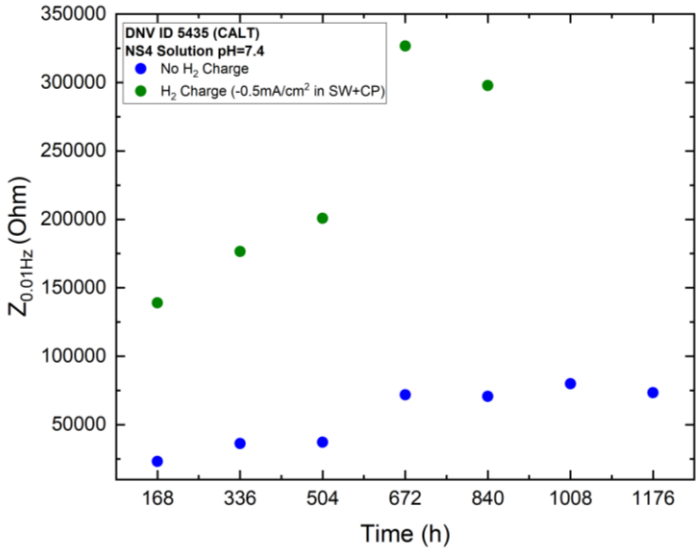

Figure 6 – Lower frequency impedance ($Z_{0.01Hz}$) of CALT control and hydrogen charged samples.

Figure 7 shows the top view of CALT samples after exposure in NS4 under none and hydrogen charging conditions. Both samples exhibited deformation around the O-ring used to seal cells and avoid leaks. No corrosion products are observed in the artificial defect. At room temperature, CALT coatings exhibit noticeable deformation due to the viscoelastic nature of their adhesive layer. The relatively soft adhesive readily conforms to the curved geometry of the O-ring, leading to localized compression, indentation, and lateral flow of the adhesive material under sustained contact pressure. Even without elevated temperature, time-dependent creep could occur, causing the coating to progressively mold around the O-ring and reduce local thickness at the point of contact. This deformation is largely non-elastic, leading to a limited recovery once the load is removed, and it reflects the design of CALT coatings and the intention to accommodate surface irregularities. However, such localized deformation can also influence interfacial stress distribution and may create preferential pathways for fluid ingress if the pressure is maintained for extended periods.

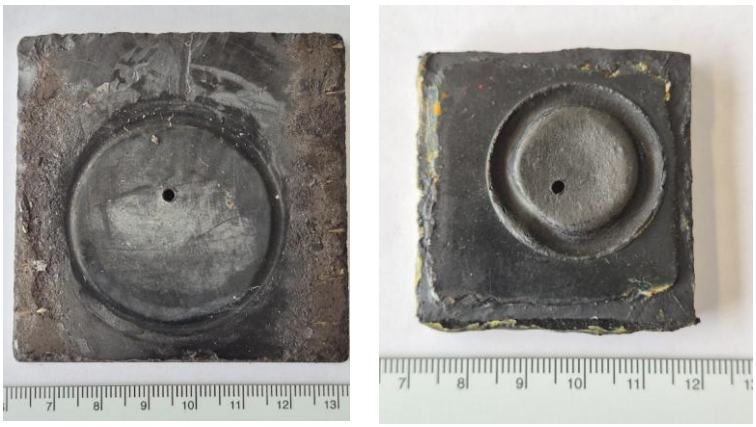

Figure 7 - CALT Top view of samples after exposure to NS4 at room temperature. Left, CALT control sample. Right, CALT sample charged with hydrogen.

Additional pull off tests were attempted on the control and hydrogen charged samples to assess any changes due to interaction of the coating with hydrogen flux; however, the results were inconclusive. Conducting an adhesion pull-off test on a CALT coating may be challenging due to the fundamental adhesion mechanism of these systems is incompatible with the assumptions of the test. CALT coatings rely on a pressure-sensitive adhesive, typically butyl- or rubber-based, which adheres through viscoelastic wetting of the substrate under applied pressure rather than through chemical bonding or curing. Pull-off tests assume a rigidly bonded coating with a relatively fixed interfacial strength. When applied to a pressure-sensitive adhesive, the measured force reflects time-dependent adhesive flow and relaxation rather than true adhesion to the substrate. Under the tensile loading imposed by a pull-off test, CALT undergo significant elastic and viscoelastic deformation. The backing film stretches and the adhesive layer shears, cavitates, and relaxes as the load increases. Instead of a sharp, well-defined failure point, deformation progresses gradually, producing results that are highly dependent on loading rate, temperature, and dwell time. This behavior prevents the identification of a meaningful or repeatable adhesion strength. Failure during pull-off testing of cold-applied laminate tapes typically occurs within the tape system rather than at the tape/substrate interface. In addition, the requirement to bond a rigid dolly to the tape surface introduces further complications. The outer surface of a cold-applied laminate tape is often polyethylene or another low-surface energy material, making reliable bonding with epoxy difficult. Dolly debonding, adhesive damage during preparation, or stress concentration caused by stiffness mismatch can all lead to premature or misleading failures unrelated to tape adhesion to steel. Based on these results, samples were cut and prepared to examine the cross section.

Figure 8 presents cross-sectional optical micrographs of CALT coating in the as-received, control (exposed, uncharged), and electrochemically charged with hydrogen at −0.5 mA/cm^2 conditions. The top row shows the general coating–substrate interface, while the bottom row highlights the response of the coating around the artificial defect.
In the as-received condition, the CALT coating exhibits a continuous, well-adhered structure. The laminate backing remains intact, and the adhesive layer shows intimate contact with the steel substrate without visible gaps or interfacial defects. The control sample, which was exposed to NS4 solution but not hydrogen charged, shows no significant changes relative to the as-received coating. The coating steel interface remains continuous, and there is no evidence of interfacial debonding or cracking. The lower control image shows deformation around the defect, likely a result from drilling the hole. The coating has flowed and conformed to the imposed geometry rather than cracking or delaminating, demonstrating the inherently viscoelastic and ductile response of the CALT adhesive and backing under compressive loading. The sample charged with hydrogen at −0.5 mA/cm^2 shows that the coating remains adhered to the steel and no gross interfacial disbondment is observed, subtle changes can be seen at the adhesive region and within the coating body around the defect. Overall, no significant changes are observed that could be related to damage due to interaction of CALT with hydrogen.

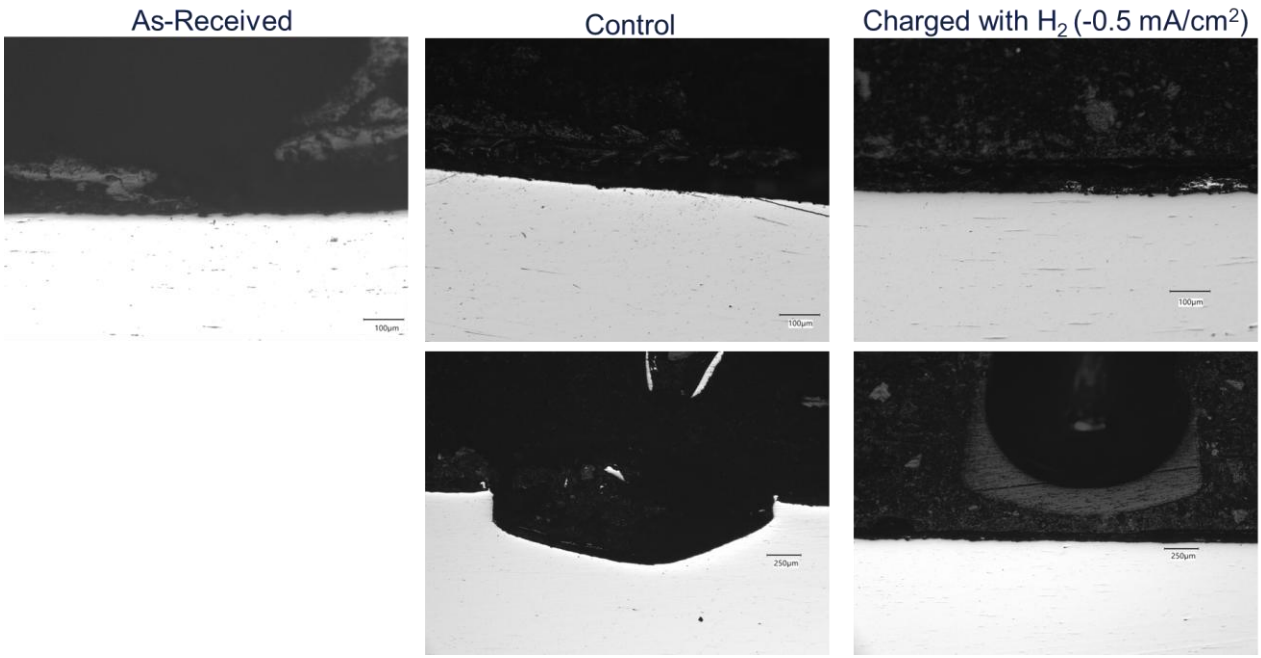

Figure 8 – Cross section of CALT samples.

5.2.2 CTE Sample

Figure 9 shows the evolution of the low frequency impedance magnitude ($Z_{0.01Hz}$) as a function of time for a coal tar enamel (CTE) coating exposed to NS4 solution at near-neutral pH. The control sample exhibits impedance values in the order of 100 - 1000 kΩ, with modest changes over exposure time. This behavior is consistent with the known characteristics of CTE coatings, which are thermoplastic, bituminous materials with comparatively high permeability to water and ions. Upon immersion in a soil-simulating electrolyte such as NS4, CTE could absorb water relatively quickly, leading to increased ionic conductivity through the coating and activation of electrochemical processes at the steel/coating interface. In contrast, the hydrogen charged sample shows impedance values two orders of magnitude higher at early exposure times. This marked increase can be attributed primarily to the effects of cathodic polarization and hydrogen evolution at the steel surface which could create bubbles on the defect induced on the CTE resulting in a high resistance. Based on this, the experimental procedure was modified to accommodate flushing the area to remove any bubbles. Additionally, any corrosion product present in the defect could also result in higher impedance values. With increasing exposure time, the impedance of the hydrogen charged sample shows scatter and a tendency to decrease. This trend suggests that the impedance enhancement associated with hydrogen charging was at least partially transient. Over time, hydrogen can diffuse away from the interface, and continued electrolyte exposure can favor water uptake and transport through the coal tar enamel. As explained before, the impedance results were complemented with visual inspection, pull off tests and cross section analysis.

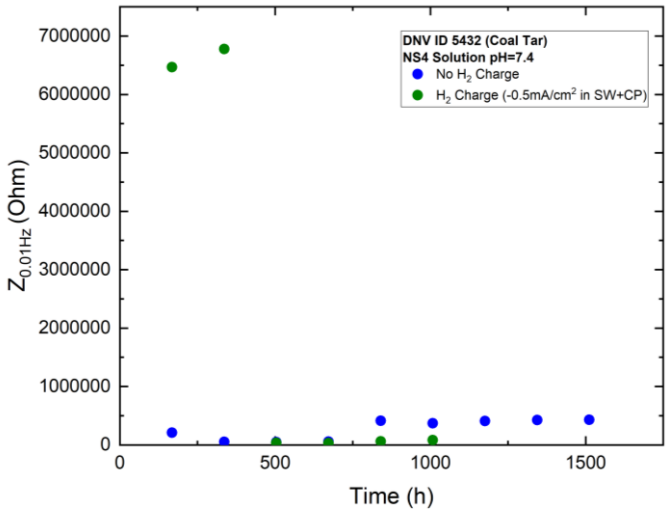

Figure 9 - Lower frequency impedance ($Z_{0.01Hz}$) of CTE control and hydrogen charged samples.

Figure 10 shows the top view images of CTE control and hydrogen charged samples. Both samples exhibit deformation around the O-ring area. No corrosion products are evident around the artificial defect. The deformation is further promoted by the low modulus and low hardness inherent to coal tar enamel, especially at room temperature or slightly elevated temperatures. Under compression, stresses are concentrated along the narrow contact line of the O-ring. In CTE coatings, these stresses can exceed the yield resistance of the bituminous phase, causing the coating to displace laterally. This behavior contrasts with more rigid epoxy or polyurethane coatings, which can better resist localized compressive loading without significant shape change.

Environmental exposure also plays an important role in the electrochemical response of these samples. CTE readily absorbs water and organic constituents from soil or electrolyte environments, which plasticizes the bitumen matrix. Water uptake reduces intermolecular cohesion within the coal tar phase, lowering stiffness and increasing susceptibility to deformation under mechanical load. If the O-ring compression occurs after electrolyte exposure, the coating is more prone to indentation and flow.

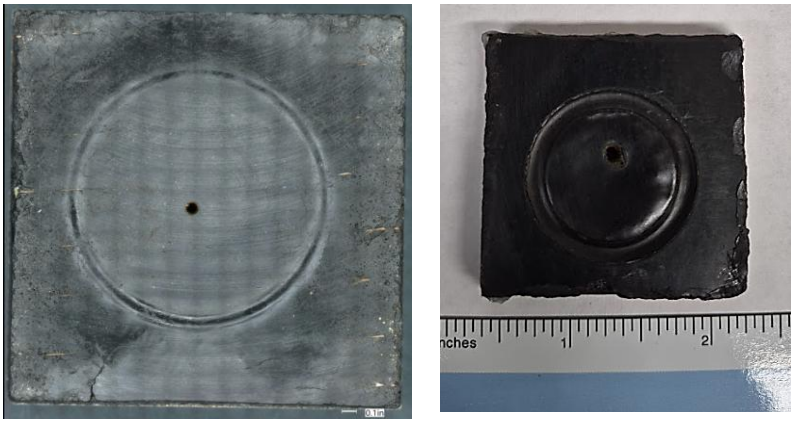

Figure 10 – CTE Top view of samples after exposure to NS4 at room temperature. Left, CTE control sample. Right, CTE sample charged with hydrogen.

After visual inspection, the samples were subjected to pull off tests. As seen in Figure 11, the pull off test was not compatible with CTE. When tensile stress is applied through a pull off dolly, the coating does not store elastic strain energy and fracture cleanly. Instead, it undergoes plastic flow and creep, redistributing the applied stress over time. As a result, the coating may elongate, neck, or deform extensively without producing a distinct failure event. The test often indicates low apparent “adhesion” values that reflect material yielding, not true loss of adhesion to the steel substrate. Another critical limitation is the low cohesive strength of CTE relative to the stresses imposed by pull-off testing. Even when adhesion to steel is adequate, the tensile load concentrates within the bulk of the coating beneath the dolly. This

commonly results in cohesive tearing, smearing, or cold flow of the enamel rather than a sharp cohesive fracture or interfacial separation. Because the failure mode is dominated by viscous deformation, the measured pull off strength is neither reproducible nor representative of coating performance. Additionally, in CTE systems, the adhesive bond is often stronger than the enamel itself, causing deformation or failure within the coating during glue curing or alignment.

Figure 11 – CTE Pull off test assembly and results.

Figure 12 contains the cross-sectional optical micrographs of a CTE coating under as-received, a control exposure, and electrochemically charged with hydrogen. In the as-received condition, the CTE coating exhibits the characteristic layered and highly heterogeneous structure typical of coal tar–based materials. The coating appears relatively thick and dark, with visible inclusions and filler-rich regions embedded within the bituminous matrix. The interface between the coating and the substrate is continuous and well defined, with no obvious large-scale separation or void formation. This microstructure is representative of a thermoplastic, viscoelastic material that has been applied hot and subsequently cooled, resulting in internal textural features but overall good adhesion in the unexposed state.

The control sample, which was exposed to NS4 without hydrogen charging, shows no significant differences when compared to the as-received condition. Localized deformation is evident near the artificial defect, and this is consistent with viscoelastic creep under contact or constraint.

In contrast, in the hydrogen-charged sample, the CTE layer appears to have flowed extensively, forming smooth, rounded profiles and with local thinning or detachment from its original geometry. This might be a result of the compression to which the sample was subjected during testing. Overall, no significant differences are observed when compared to the as-received and control samples.

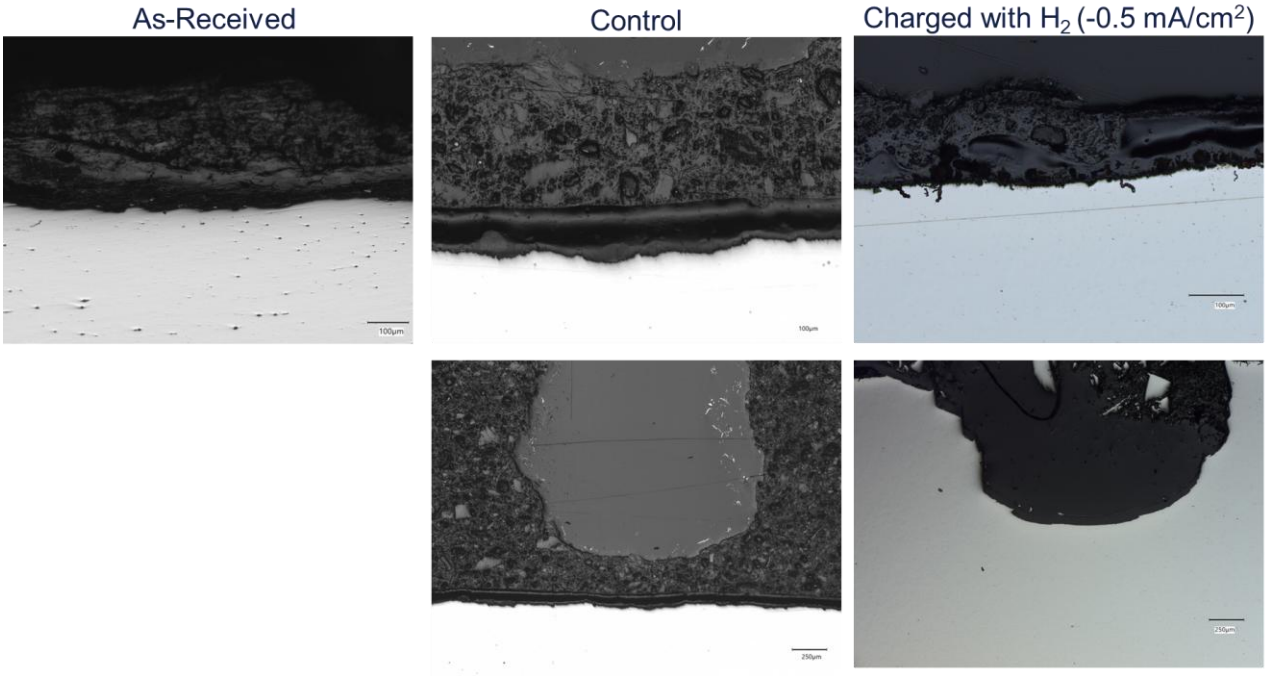

Figure 12 – Cross section of CTE samples.

5.2.3 FBE Sample

Figure 13 shows a summary of the low frequency impedance for the control and hydrogen charged FBE samples. For the control sample, where no hydrogen charging was applied, the impedance values are initially in the mid 10^4-10^5 Ω range and show a gradual decrease with time. This behavior is associated with progressive water uptake into the epoxy matrix. As water and ions permeate the coating, and reach the defect, its electrical resistance decreases and electrochemical activity at coating defects or pores becomes more pronounced. After the initial exposure period, the impedance tends to stabilize at lower values, indicating the establishment of a quasi-steady state in which the coating continues to act as a barrier, albeit with reduced resistance due to electrolyte ingress.

In contrast, the hydrogen-charged samples show markedly higher impedance values at early exposure times, with $Z_{0.01Hz}$ exceeding $2x10^5$ Ω. This initially elevated impedance could be related to hydrogen adsorption at the steel surface and changes in interfacial charge transfer kinetics temporarily increasing the measured impedance, giving the appearance of improved barrier performance even though the intrinsic properties of the coating have not necessarily improved. As exposure time increases, the impedance of the hydrogen charged samples decreases sharply, eventually approaching values similar to, or only slightly higher than, those measured for the control samples. This may suggest no significant effect from hydrogen charging; however, further visual inspection and pull off tests were conducted to complement these results.

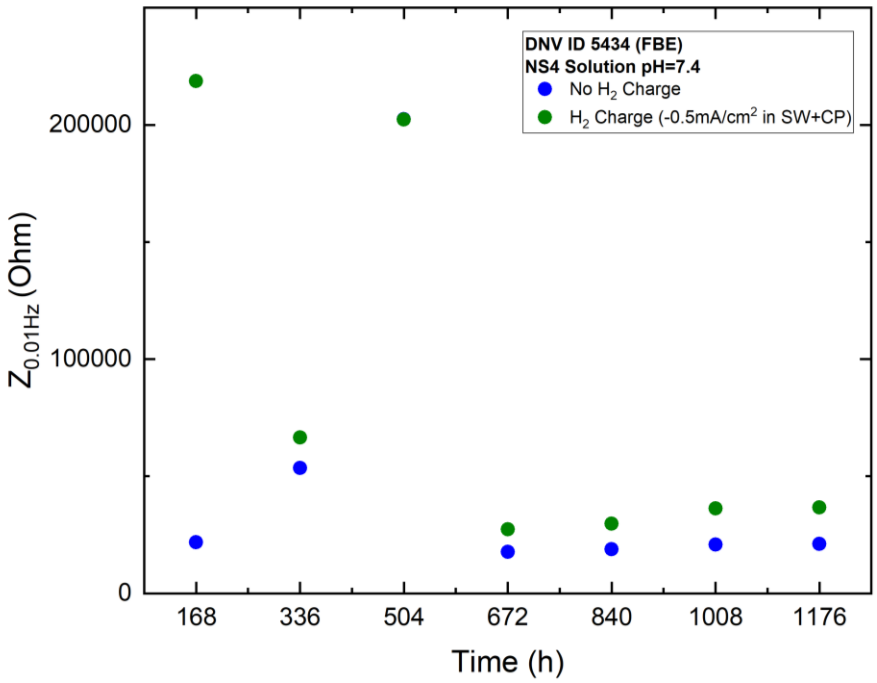

Figure 13 - Lower frequency impedance ($Z_{0.01Hz}$) of FBE control and hydrogen charged samples.

Figure 14 shows the top view of the control and hydrogen charged FBE samples. Both samples show signs of discoloration and corrosion product in the defect. No signs of blister or delamination are observed. Discoloration of the FBE coating is primarily associated with water uptake, chemical exposure, and pigment or filler degradation within the coating system. FBE coatings are inherently hygroscopic, and exposure to soil solutions or simulated soil electrolytes promotes moisture absorption into the epoxy matrix, leading to plasticization and changes in the local refractive index that manifest as lightening, cloudiness, or non-uniform color variation. Water ingress also facilitates chemical interactions between the coating and environmental species such as chlorides, sulfates, or locally acidic or alkaline constituents, resulting in chemical modification of the epoxy network. Additionally, pigments and fillers within the FBE, such as titanium dioxide or iron-based compounds, are susceptible to interaction with moisture and electrolytes, leading to oxidation, leaching, or migration.

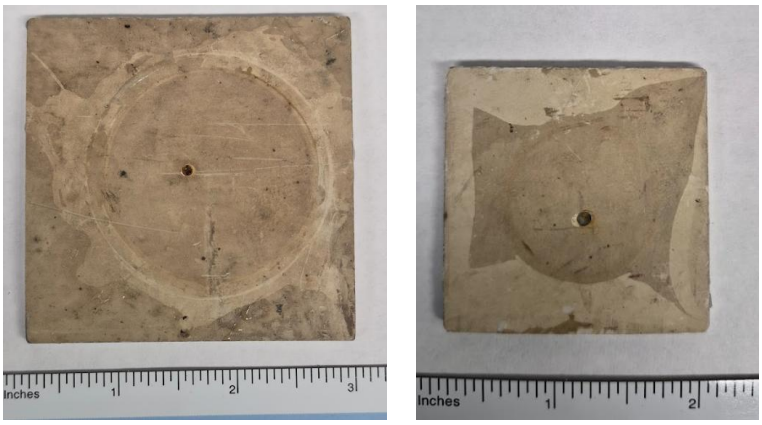

Figure 14 – FBE Top view of samples after exposure to NS4 at room temperature. Left, FBE control sample. Right, FBE sample charged with hydrogen.

Pull off adhesion testing was performed on FBE coated steel samples in the as-received, control, and hydrogen-exposed conditions (Table 2). The as-received FBE samples exhibit an average pull-off strength of 1145.8 kg (2526 lbs), indicating good adhesion consistent with a properly applied and cured coating. The control samples exposed to NS4 solution showed a similar average pull-off strength of 1154.8 kg (2546 lbs), which falls within normal experimental variability relative to the as-received condition. This similarity indicates that exposure of the coating surface to NS4 has no measurable adhesion degradation over the test duration, suggesting minimal impact from water uptake or ionic ingress under these conditions. The hydrogen exposed sample shows a reduced average pull-off strength of 2048 lbs, corresponding to an approximately 20% decrease compared to both the as-received and control samples. It is worth noting that due to the small geometry of the hydrogen charged sample, just two adhesion measurements were possible. This is relevant to the interpretation of these results and the possibility of more data points to assess whether the difference is merely related to statistical scattering. Considering this, the cross section of these samples was analyzed.

Table 3 - Pull off results for the FBE samples

Sample reference	Test 1	Test 2	Test 2	Average
As received	1020.1 kg (2249 lbs)	989.3 kg (2181 lbs)	1428.4 kg (3149 lbs)	1145.8 kg (2526 lbs)
Control	1216.5 kg (2682 lbs)	1093.2 kg (2410 lbs)	N/A	1154.8 kg (2546 lbs)
Hydrogen exposed	796.1 kg (1755 lbs)	1061.9 kg (2341 lbs)	N/A	929.0 kg (2048 lbs)

Figure 15 compares cross-sectional micrographs of FBE-coated steel in the as-received condition, after exposure of the coating side to NS4 soil-simulating solution (control), and after combined NS4 exposure and hydrogen charging. In the as-received state, the FBE coating is uniform and well adhered to the steel, with a smooth and continuous interface. Following NS4 exposure alone, the control sample shows minor interfacial waviness and localized coating deformation, consistent with limited electrolyte uptake and slight softening of the FBE, but no clear evidence of interfacial debonding or coating failure. It appears that the hydrogen charged sample shows the same features as the as-received and control samples, indicating no significant effect of hydrogen under the selected experimental conditions.

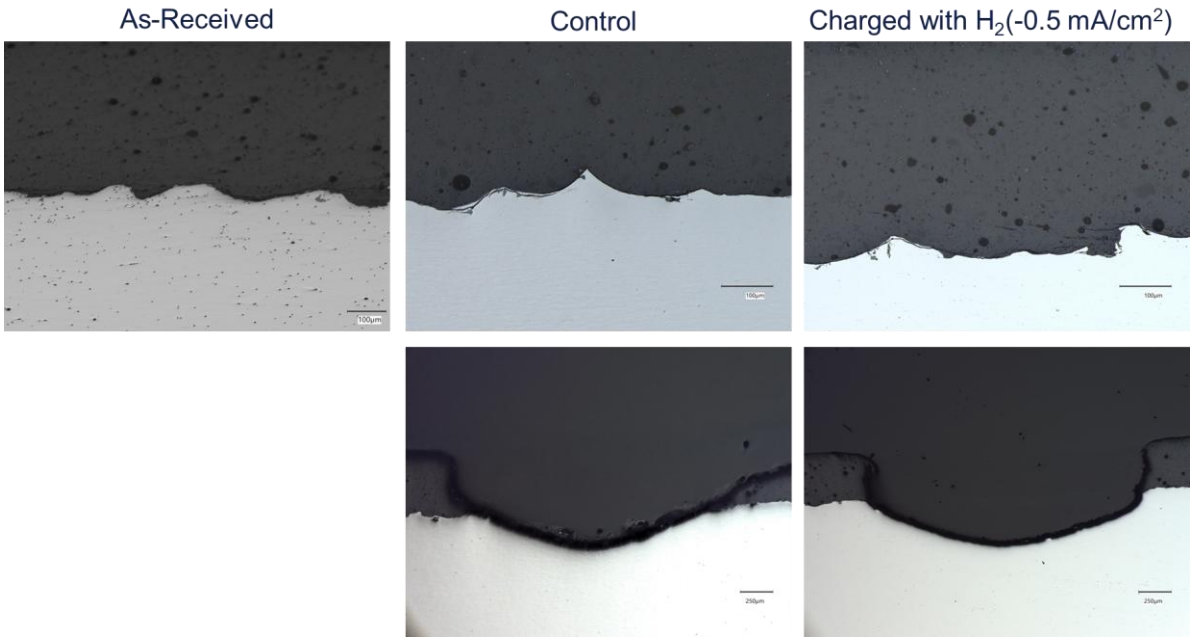

Figure 15 – Cross section of FBE samples.

5.2.4 FBE+MCL Sample

Figure 16 presents the evolution of impedance at 0.01 Hz as a function of exposure time for steel samples coated with FBE with MCL extracted away from the weld area. The control sample shows a progressive decrease in impedance with exposure time. The initial impedance values decline steadily, indicating ongoing changes within the coating system associated with environmental exposure. This behavior might be consistent with increasing electrolyte permeation through the coating and progressive degradation of the coating and coating/steel interface in the presence of NS4. The hydrogen-charged sample shows higher impedance values throughout the exposure period compared to the control condition. Although impedance decreases with time, the reduction is less pronounced, and the values remain elevated relative to those measured for samples without hydrogen charging. This may be a result of corrosion products in the defect or resistance related to the presence of hydrogen bubbles.

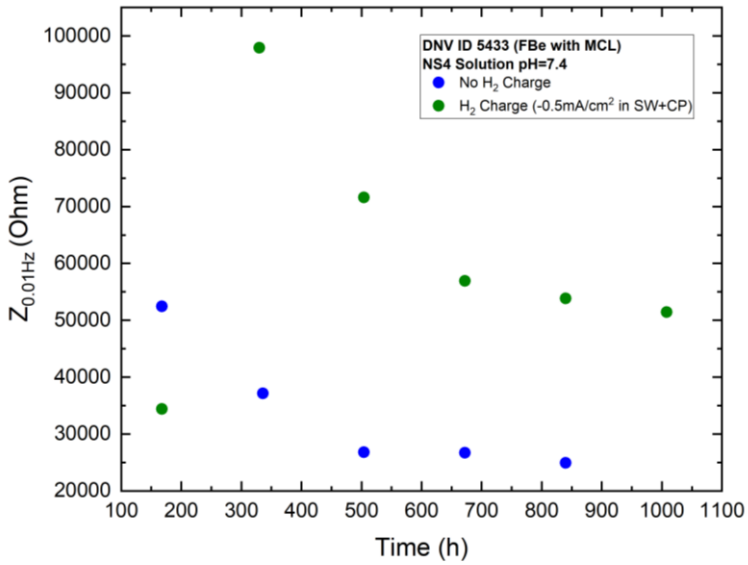

Figure 16 - Lower frequency impedance ($Z_{0.01Hz}$) of FBE with MCL control and hydrogen charged samples.

Figure 17 shows the top view of FBE with MCL samples evaluated in this program. Both samples show peeling of the MCL outside the exposure to NS4 area which confirms a brittle nature. No signs of blistering or delamination are

observed; however, discoloration is observed in the area in contact with NS4 along with corrosion product in the defec for both the control and hydrogen charged samplest. Discoloration of a multi-component liquid layer generally indicates chemical reactions, environmental degradation, phase instability, or interactions with surrounding materials. The specific cause is often system dependent and usually reflects a change in composition or structure rather than a benign aging effect, making discoloration a useful diagnostic indicator in material and coating evaluations.

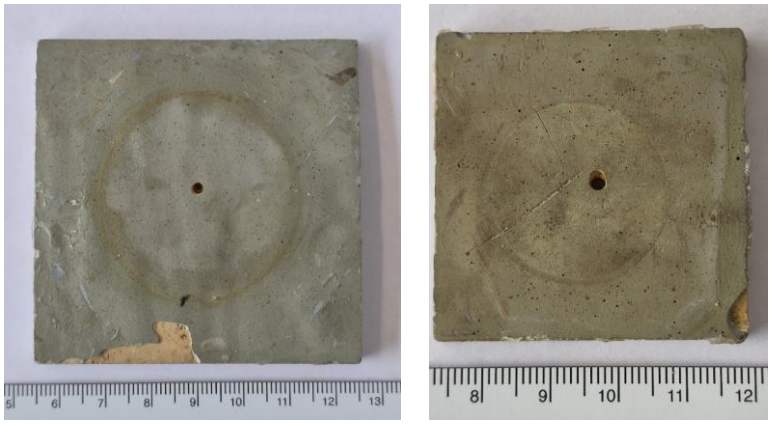

Figure 17 – FBE with MCL Top view of samples after exposure to NS4 at room temperature. Left, FBE with MCL control sample. Right, FBE with MCL sample charged with hydrogen.

The results shown in Table 4 are for pull off dollies mounted onto the MCL layer and, in all cases, there was an adhesion failure between the MCL and the underlying FBE. Further pull-off tests were performed on the exposed FBE, which gave an average value of 953 kg (2100 lbs).

Table 4 - Pull off results for MCL Layer of the FBE+MCL sample

Sample reference	Test 1	Test 2	Average
As received	421.4 kg (929 lbs)	403.2 kg (889 lbs)	412.3 kg (909 lbs)
Control	399.6 kg (881 lbs)	431.4 kg (951 lbs)	415.5 kg (916 lbs)
Hydrogen exposed	445.4 kg (982 lbs)	397.3 kg (876 lbs)	421.4 kg (929 lbs)

Figure 18 shows the cross section of the FBE with MCL in the as-received, control and hydrogen charged conditions. In the as-received condition, the FBE coating appears dense and relatively uniform, with good interfacial contact to the steel substrate. The MCL layer on top of the FBE seems to be continuous, with no obvious signs of interfacial separation or extensive defect formation. Minor dark features observed within the coating are consistent with inherent porosity or fillers typical of FBE systems and do not indicate degradation. Overall, this condition represents the baseline microstructure prior to environmental or electrochemical exposure. For the control and hydrogen charged samples, the coating and MCL layer remain largely intact with no visible signs of damage around the defect. The NS4 exposure can promote limited water uptake into the FBE, leading to slight swelling or increased contrast variations within the coating. However, the interface between the steel and FBE remains continuous, and there is no clear evidence of large scale disbondment or cracking. This indicates that exposure to simulated soil solution alone may slightly influence the coating through hydration and ionic ingress rather than through severe interfacial degradation under the experimental conditions selected for this program.

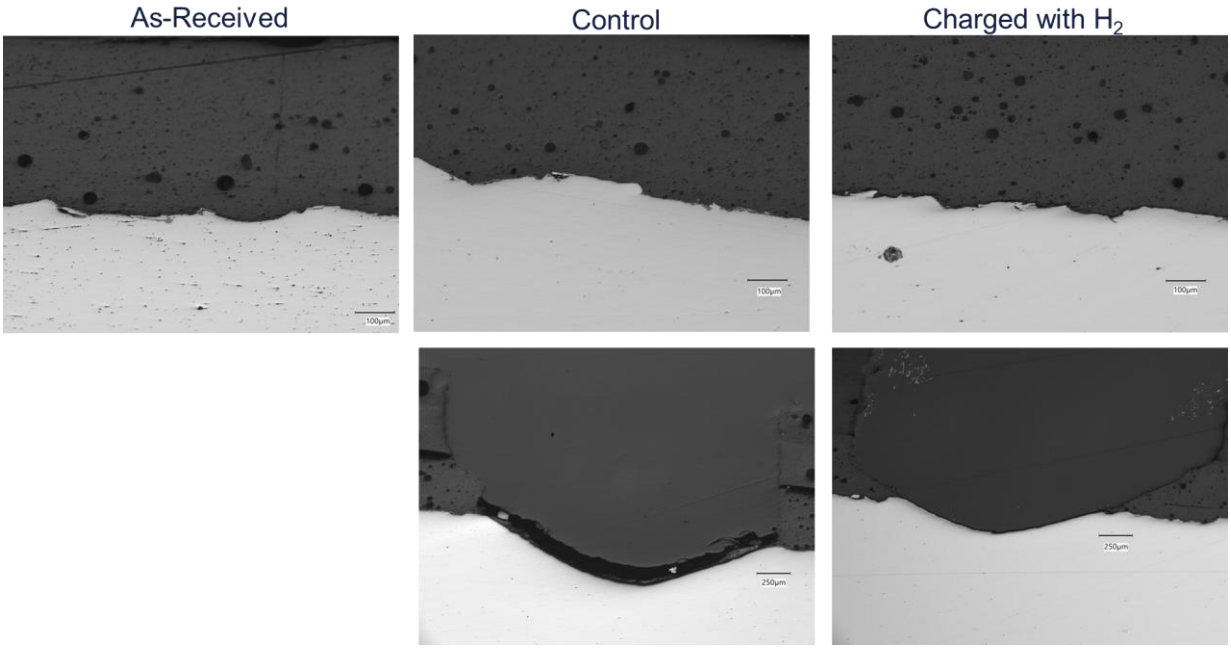

Figure 18 – Cross section of FBE with MCL samples.

5.3 Results Conclusions

Based on the result discussed above it has been concluded that, based on a relatively short (7 week) exposure to hydrogen at rates which are considered a conservative maximum hydrogen flux rate on the NTS, there is no substantial evidence presented by these results which suggest that any of the coatings assessed experienced degradation when exposed to hydrogen. There is no suggestion that there was damage to the steel-coating interface in any case, which is ultimately responsible for preventing corrosion. Visual inspection, pull off testing, and cross-sectional analysis confirmed that coating behavior was strongly governed by material properties. CALT and CTE coatings exhibited significant viscoelastic deformation rendering pull off adhesion testing inconclusive, while microscopy showed no hydrogen-induced interfacial damage. FBE coatings showed discoloration and a modest reduction in pull-off strength after hydrogen charging, but no evidence of blistering, delamination, or interfacial disbondment. For FBE+MCL systems, adhesion consistently failed at the MCL/FBE interface regardless of exposure, indicating an inherent interlayer weakness rather than hydrogen-related degradation.

6 Considerations for changes to policies and procedures

To assess the implications of hydrogen transportation on pipeline operations with respect to external corrosion mechanisms and mitigation strategies, a review of relevant procedures and internal standards was undertaken. From the document review, the overarching themes detailed in Table 5 were identified within the scope of work of this project and will be further discussed.

Table 5: In scope query theme summary table

Query Theme
Should surface preparation principles change for hydrogen service?
Are the existing external coatings on the pipelines suitable for hydrogen service?
Will existing external coating application principles change for the pipelines in hydrogen service? If so, what considerations should be made?
Will coating disbondment rates and/or corrosion rates increase in hydrogen service?
Are current ILI tools compatible with hydrogen? Are there any existing or novel ILI techniques that are recommended for a hydrogen pipeline?
Are traditional inspection techniques still applicable and what additional techniques may be required for hydrogen service?
Does the approach to pipeline coating surveillance change for hydrogen service?
Does hydrogen transportation introduce additional damage mechanisms to pipelines?
Will CP thresholds need to be reconsidered for hydrogen service?
Will the current repair methods in use on the pipelines change for hydrogen service?
How will pressure reduction levels change in hydrogen service due to external corrosion damage specifically?
Do weld arc strikes increase the risk of corrosion for a hydrogen pipeline?
Should the current requirements for wall thickness loss investigation due to external corrosion change for hydrogen pipelines?

The following sections discuss these query themes and suggest changes which should be considered for pipeline policies and procedures with regards to coatings and corrosion control.

6.1 Surface Preparation

Should surface preparation principles change for hydrogen service?

All coatings data sheets will include a specification for the surface preparation of the surface to which the product will be applied. These requirements are designed to give the coating the best adhesion to the underlying surface. While the coatings recommended for use in hydrogen service may change, a given operator's approach to surface preparation should all be guided by the coating manufacturer.

6.2 Coatings

Are the existing external coatings on the pipelines suitable for hydrogen service?

Will coating disbondment rates and/or corrosion rates increase in hydrogen service?

The results of the test program do not suggest that the coatings assessed suffer from hydrogen induced damage to the bulk of the coatings, nor does hydrogen cause coating disbondment over the 7-week test period. Therefore, currently, there is no experimental evidence to suggest that the coatings are not suitable for hydrogen service.

However, this study presents a relatively short-term study of coatings that were applied to pipelines and allowed to cure without the presence of hydrogen. In the event of network conversion to hydrogen, detailed surveillance of the network

over the first few years of operation would be required to monitor for a range of possible issues, the continued operation of corrosion protection mechanisms being among them.

Will existing external coating application principles change for the pipelines in hydrogen service? If so, what considerations should be made?

As discussed in section 6.1 with regards to surface preparation, the approach to coating application is led by the manufacturer recommendations for each product used. This will not change in a hydrogen transportation scenario, although some of the coatings used may change. Engagement with manufacturers throughout the transition to a hydrogen system will be key to ensure that all coatings used are appropriate.

There are some considerations on coating application which may change in hydrogen service which have not been fully investigated within this project, which would be important to highlight when discussing with manufacturers. One which has been highlighted during technical discussion is that it is possible that if hydrogen flux is occurring on the pipeline during operation, this hydrogen might affect the drying/curing of repairs and coatings which are applied to the pipeline in service.

6.3 Inspection Techniques

Are current ILI tools compatible with hydrogen? Are there any existing or novel ILI techniques recommended for a hydrogen pipeline?

Hydrogen compatible corrosion detection ILI tools are currently available, although their availability is limited due to limited demand. Ultimately, ILI providers will keep driving the development of these tools as the future of the hydrogen economy becomes more certain.

Future ILI campaigns are likely to require the use of crack detection tools based on technologies such as EMAT or UT vehicles to manage the fatigue risk for hydrogen pipelines. Vendors are improving the capabilities of these tools but currently they have not been demonstrated on operational hydrogen pipelines.

Are traditional inspection techniques still applicable and what additional techniques may be required for hydrogen service?

Currently, the surveys commonly used on pipelines are are Close Interval Potential Surveys (CIPS), DC Voltage Gradient (DCVG), Pearson surveys, Electromagnetic Current Attenuation (ECA) and Current Drain Tests. There is currently no evidence that these methods would not be effective on a hydrogen pipeline.

DNV therefore predict that these inspection techniques will remain relevant and appropriate in hydrogen service. However, depending on the effect of hydrogen on the coatings (if any) it may be advisable to adjust the inspection frequencies and potentially the classification of defects to reflect the mechanisms of any hydrogen-based coating degradation.

Will the approach to pipeline coating surveillance change for hydrogen service?

Currently the approach to inspection is time based rather than risk based. When the relevant safety reviews are completed for the operation of the NTS under hydrogen service this may change, either by changing the periods advised between inspection or by moving to a risk-based approach.

6.4 Cathodic Protection

Will CP thresholds need to be reconsidered for hydrogen service?

The thresholds for CP are currently commonly defined with the minimum protection criteria set at -850 mV (or -950 mV for areas with suspected sulphate reducing bacteria). This value is ultimately determined by the rest potential of steel, which will be unchanged. There is then a conservatism added to account for differences in soil resistivity and other

variation in conditions across the length of the pipeline, and the value is set to -850 mV. DNV would not recommend a change to this value based on current information.

The overprotection criteria is currently commonly set at -1150 mV vs a Cu/CuSO4 reference electrode. If the voltage is allowed to go lower than this, coating disbondment is known to occur and hydrogen evolution is possible even in natural gas pipelines. While the effect of hydrogen on CP was not a primary focus of this work, the issue of coating disbondment is related to electrochemical charging. Therefore, it is conceivable that the addition of hydrogen diffusing through the metal could add to this mechanism and make the system more sensitive, requiring the movement of the overprotection criteria to a more conservative value. An additional consideration is that the formation of hydrogen bubbles at the steel surface can lead to fluctuations in the measured potential due to disruptions in the local electrochemical environment. This effect is probably too localised to affect the control of CP systems but may influence the results of DCVG surveys. In addition, the presence of hydrogen evolution at high rates can make the system more susceptible to potential fluctuations caused by external alternating or direct stray currents, as the overall system impedance and reaction kinetics are altered.

As mentioned in Section 6.2, the conversion of a network to hydrogen would lead to a period of increased surveillance for the network. The efficacy of CP under hydrogen service should be reviewed under this program, looking to determine whether increased rates of coating disbondment are found and whether these correlate to areas of increased cathodic protection levels.

6.5 Repair Methods

Will the current repair methods used on the pipelines change for hydrogen service?

As with the assessment of coatings in this scope of work, the suitability of repair methods is one of materials compatibility. There is cross-over between the materials used in coatings and repair methods and therefore the results of the test program may inform the suitability of some repair techniques.

Other repair methods and materials should be assessed either by liaison with the manufacturers and/or further evaluation led by NG to develop acceptance criteria for repair methods in hydrogen service.

The findings of the test program have not highlighted any materials compatibility issues with the coating materials assessed.

6.6 Miscellaneous

How will pressure reduction levels change in hydrogen service due to external corrosion damage specifically?

When considering the conversion to hydrogen, it will be necessary to reconsider the risk assessment for the operations and activities which occur on the pipelines. It is likely that for issues such as this a higher level of conservatism would be appropriate in a hydrogen transport scenario.

The test program and literature review do not suggest that an increase in corrosion rates is expected, and therefore the scope of this discussion would be focussed on the safety considerations for pipeline workers in the event of a loss of containment on a hydrogen system, rather than a natural gas system.

Do weld arc strikes increase the risk of corrosion for a hydrogen pipeline?

Weld arc strikes can significantly increase the risk of hydrogen embrittlement and cracking in steel pipelines because they create hardened, highly stressed areas (hard spots) that trap hydrogen atoms. The strike contains a hard, brittle heat-affected zone (HAZ) containing martensite. This effect has been observed in natural gas pipelines which become hydrogen charged due to CP overprotection and in delayed cracking of welds at the arc strike location. Although potentially corrosion could be enhanced by galvanic interactions between the differing microstructures of the arc strike and base material the presence of coatings and cathodic protection should mitigate any increased corrosion rates.

Should the current threshold for wall thickness loss investigation due to external corrosion change for hydrogen pipelines?

When the risk assessment for the system is considered, it may determine that greater conservatism in a number of areas is more appropriate to the consequence of a loss of containment of hydrogen when compared to natural gas. This work may advise that the level of external corrosion which can be tolerated would be lower in a hydrogen transport scenario. This work does not suggest that corrosion rates are likely to increase in a hydrogen transport scenario compared to a natural gas transport scenario.

7 Summary and Conclusions

This work has investigated whether converting pipeline networks to hydrogen could lead to an increased corrosion risk to the pipelines. First, the corrosion mechanisms present on GB pipeline networks were discussed, and the potential impact of hydrogen on those mechanisms was researched in the literature. The following mechanisms and findings were discussed:

- General Attack Corrosion (External Corrosion).
  - As hydrogen is a natural byproduct of the corrosion reaction, increased hydrogen concentrations are not thought likely to increase corrosion rates.
- Pitting Corrosion.
  - While hydrogen could in theory influence the initiation of a pit, the corrosion reaction at the bottom of a pit, which leads to wall loss is the same chemical reaction as general attack corrosion, and therefore hydrogen is not expected to increase corrosion rates.
- Crevice Corrosion.
  - Hydrogen has been shown to increase rates of corrosion in stainless steel but research is very limited in pipeline steels.
- Corrosion under Insulation (CUI).
  - As with general attack corrosion, hydrogen is a product of the reaction and therefore is not expected to accelerate corrosion.
- Stress Corrosion Cracking.
  - GB pipelines are not considered at risk of internal stress corrosion cracking as they transport dry gas.
  - The mechanisms by which hydrogen could affect Near Neutral Stress Corrosion Cracking are not fully understood in the literature at this time. However, hydrogen embrittlement is suspected to play a role.
- AC Corrosion.
  - Hydrogen does not influence the mechanisms by which AC corrosion occurs.

Then the corrosion prevention mechanisms present on the network were discussed, along with the potential impacts of hydrogen on their efficacy. Pipelines utilise both coatings and paint to provide a physical barrier between the steel pipeline surface and the environment. When considering buried pipelines, which are more challenging to inspect, four common coating types were identified. These were FBE and CTE, which account for most pipelines, as well as CALTs and MCLs. These were taken forward for the test program.

It was considered that hydrogen could have two possible detrimental effects on paints and coatings. Hydrogen could recombine at the steel-product interface and cause a build-up of pressure, causing the bond between the steel and product to fail. This process is commonly known as blistering. However, if the hydrogen can diffuse through the coating/paint at a rate faster than it is able to diffuse through the steel, it will not be possible for a volume of hydrogen to build up. Considering the difference in density between steel (broadly 7.75 to 8.05 g/cm^3) and common coating materials such as FBE (broadly 1.3 to 1.5 g/cm^3), it is expected that coating and paint materials are unlikely to trap hydrogen effectively.

It is also possible that hydrogen could react chemically with the bulk of the coating or paint, causing changes to the chemical structure of the material which could lead to it breaking down and no longer protecting the pipe. However, many of the component materials identified during this work are listed as compatible with hydrogen in numerous industrial standards, which gives confidence that this is unlikely.

The test program exposed the 4 coating types (FBE, CTE, CALT and FBE+MCL) to hydrogen flux rates considered as realistic but conservative for a pipeline carrying 70 bar hydrogen for a period of 7 weeks. The condition of the coating was measured using EIS, and after the testing the samples were subject to pull off testing and SEM analysis of the coating/steel interface. No notable differences were recorded between the hydrogen exposed samples compared to the control samples.

Review of internal standards for the operation of pipelines were reviewed to identify areas where changes would be needed to safely operate pipelines in hydrogen service. As the literature review and test results offer no strong evidence that in service coatings would be unsuitable for hydrogen service. Overall, no changes to the policies and procedures are recommended at this time regarding corrosion control.

7.1 Conclusions

The following conclusions are therefore drawn from this program:

- There are a number of credible corrosion threats to GB pipelines which are all focussed on mechanisms where moisture can reach the external surface of the pipe. Additional corrosion-based mechanisms are not expected in a hydrogen transport scenario.
- Of the credible corrosion mechanisms, only pitting, crevice corrosion and Near Neutral SSC are believed to be possibly influenced by hydrogen.
    - Hydrogen could influence the initiation of pits but then would not be expected to accelerate corrosion within pits.
    - The effect of hydrogen on crevice corrosion on ferritic carbon steels used for NTS components is not clear. Initiation and propagation of crevices is enhanced by hydrogen in stainless steels.
    - Hydrogen is known to accelerate Near Neutral SCC in stainless steel, but there is an absence of data in carbon steel so the extent of its possible influence on GB pipelines is currently unknown.
- Of the current corrosion protection systems used on GB pipelines, it is believed that deleterious interactions between hydrogen and coatings, paints and CP systems are unlikely. Current hydrogen standards such as ASME B31.12 provide guidance on the appropriate use of sleeves and repairs.
- The test program has demonstrated that over a 7-week exposure time no deleterious effects of hydrogen exposure were noted on 4 ex-service coatings (FBE, CTE, CALT and FBE+MCL). This gives confidence that hydrogen would not have a deleterious effect on pipeline coatings in the short term. No change in observed corrosion was noticed on any of the samples.
- A review of relevant policies and procedures highlighted key questions for a hydrogen transport scenario. As this work suggests that there would be no initial change to coating integrity or corrosion rates, no changes to approach is recommended. However, hydrogen conversion would require reconsideration of several safety related polices in terms of risk to personnel etc.

7.2 Recommendations

The following recommendations are made from the findings of this program:

- While the test program found no deleterious effects of hydrogen, this short-term testing cannot be used to confidently forecast the long-term behaviour of coatings on the network, even though it does give confidence that conversion can be achieved. In the event of conversion to hydrogen transport, additional network surveillance will be key to confirm the safe operation of the network. This should include the close monitoring of coating survey data, inline inspection data and other tools to detect areas where corrosion rates may increase.

Networks should also consider more invasive procedures at periodic intervals to ensure that coating adhesion can be tested over long-term exposure to hydrogen transport.

- The additional surveillance mentioned above should also allow for data to be collected to investigate the possibility of other mechanisms being influenced by hydrogen in the long term that were not included in the test program. These should include NNSCC and the possible interactions of hydrogen with pipeline sections with CP achieving polarities close to or below -1150 mV.
- Moving forward, networks should seek assurance from coating, paint and repair manufacturers as to their products compatibility with hydrogen. It should be noted that it is possible that coatings/paints/repairs applied to a pipeline in active hydrogen service could have their curing processes influenced by permeating hydrogen, and this test work has not investigated this possibility.
- Significant learnings and guidance can be found from existing hydrogen pipeline standards and operators with hydrogen pipelines globally. The current understanding is that the corrosion protection and pipeline surveillance systems used with existing hydrogen pipelines are very similar to those used currently in GB. This should give confidence that existing corrosion protections systems are most likely fit for purpose in a hydrogen transport scenario.

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