Managing Integrity Threats in CO_2 Pipelines with ILI

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Abstract

Carbon Capture and Storage (CCS) involves the conveyance of carbon dioxide (CO_2) through pipelines from the capture facility to a storage field. While CO_2 can be transported in a gaseous state, the dense or supercritical state is preferred due to efficiency and project economics, particularly for storage applications. This paper will review the integrity threats faced by purpose built and repurposed CO_2 pipelines and the role of in-line inspections (ILI) in detecting and sizing critical defects while overcoming the mechanical and operational challenges of this medium.

The management of time-dependent threats in CO_2 pipelines must overcome unique challenges in these high-pressure dense phase operations, which can be compounded with the presence of impurities originating from various industrial processes and applications. This paper reviews, in line with current industry understanding, the time-dependent threats which could arise in pure (naturally occurring) CO_2 and anthropogenic (man-made) CO_2 pipelines. Key gaps and challenges are highlighted.

The requirements of in-line inspection programs in CO_2 pipelines, aligned with the integrity threat review, are discussed, including specific considerations for pipeline change of product (repurposing). The paper then reviews the key design, mechanical and operational considerations and challenges associated with CO_2 pipelines, considering fluid-specific properties, in successfully 'designing' and deploying in-line inspection programs in dense CO_2. For example, the operational parameters and pipeline construction have key roles in defining the most adequate combination of in-line technologies and also the actual configuration of each cleaning pig and inspection tool. The current industry ILI limitations of diameter and pipeline wall thickness are also highlighted; this is of particular importance considering a trend of CO_2 pipeline designs asking for higher wall thicknesses to address fracture propagation and accelerated corrosion issues, to the detriment of inspection capabilities (and thus safe integrity management).

Exposure testing of tool components, customisation of tool configurations, and proving robustness both mechanically and in terms of technology repeatability through a track record all contribute to in-line inspection run success in this increasingly important medium.

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Introduction

There is a wider public acknowledgement that the path to Net-Zero requires the deployment of Carbon Capture, Utilization and Storage (CCUS) at an industrial scale. The realisation of a CCUS value chain relies on the transportation of CO_2 over long distances by pipelines to storage or users. Currently, the CO_2 pipeline landscape consists of just over 7000 kilometres, with the overwhelming majority operated in the United Sates (U.S.). In the U.S. alone, the (ambitious) goal is to multiply the existing local CO_2 pipeline infrastructure by at least tenfold by 2050.

CCUS projects aim at transporting CO_2 over long distances in its dense (liquid) state, well above the critical pressure (circa 75 bar for pure CO_2) for hydraulic efficiency and project economics, particularly for storage applications. There are key integrity threats arising from the transportation of dense CO_2. Looking at the 7000 kilometres of U.S. CO_2 pipeline infrastructure originally built in the 1970s-1990s, there is a good industry experience in managing these. Nonetheless, the core of this experience is associated with the transportation of 'quasi-pure' CO_2 captured from Natural Gas, and used for Enhanced-Oil Recovery (E.O.R). In contrast, the current and future generation of CCUS pipeline projects aim at transporting CO_2 captured from various anthropogenic (man–made) and industry sources; by nature this implies that the CO_2 will hold a much wider spectrum and higher concentrations of contaminants. This paper reviews key integrity threats arising from the transportation of dense CO_2, and in the presence of contaminants. Industry gaps and challenges are highlighted.

Particularly, the deployment of In-Line Inspections is an important piece of the integrity management jigsaw. The specific requirements of in-line inspection programs in CO_2 pipelines, aligned with the integrity threat review, are discussed. The paper reviews the key design, mechanical and operational considerations and challenges associated with CO_2 pipelines, considering fluid-specific properties, in successfully 'designing' and deploying in-line inspection programs in dense CO_2.

Note this paper principally considers transportation of dense CO_2.

Source of CO_2 and compositions

The composition of CO_2 has significant implications for the realisation of pipeline integrity threats and failure modes, and how these are safely managed during design and operational stages.

The CO_2 captured from Natural Gas sources is often described as "pure"; this is erroneous as the majority of the CO_2 pipelines in the United States transport CO_2 with impurities such as hydrocarbons (e.g. methane), nitrogen, hydrogen sulphide, hydrogen and water (see Table 1). This is acknowledged in specifications used for the pipeline transportation of CO_2 in the U.S. as illustrated in Table 1[1].

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Table 1: Example of specification of CO_2 captured from natural gas and transported in U.S. pipelines

	Levels	Min /Maximum
CO_2	95%	Minimum
Nitrogen	4%	Maximum
Hydrocarbons	5%	Maximum
Water	600 ppmv	Maximum
Oxygen	10 ppmv	Maximum
Hydrogen sulphide	10-200 ppmv	Maximum
Glycol	0.3 gal/MMcf	Maximum

Nevertheless, CO_2 streams directly generated from process plants tend to be richer in impurities. The type(s) of impurities that can be generated as a function of the industry are listed below (but may not be limited to):

- Power plant industry – H_2O, O_2, NO_x, SO_x, CO, HCN, HCl, NH_3
- Pre-combustion – H_2O, H_2, CO, H_2S, CH_4
- Post-combustion – H_2O, SO_x, O_2, NO_x
- Steam Methane Reforming (SMR / 'blue hydrogen')– N_2, H_2, CH_4, CO
- Steel plant – CO, H_2, H_2S
- Biomass – Alcohol, CH_4, H_2S
- Treatment – Glycol, Amines, Methanol

Potential impurity combinations from the three main CO_2 capture - power plant technologies (i.e. post-combustion, pre-combustion and oxyfuel) are captured in Table 2 [2]. An example of a CO_2 stream composition from a SMR plant is shown in Table 3 [3].

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Table 2: Example of impurity combinations from main CO_2 capture - power plant technologies

	POST-COMBUSTION	OXYFUEL	PRE-COMBUSTION
CO_2	>99%v.	>90%v	>95.6%v.
CH_4	<100 ppmv	0	<350 ppmv
N_2	<0.17%v.	<7%v.	<0.6%v.
H_2S	Trace	Trace	<3.4%v.
C2+	<100 ppmv	0	<0.01%v.
CO	<10 ppmv	Trace	<0.4%v.
O_2	<0.01%v	<3%v.	Trace
NO_x	<50 ppmv	<0.25%v.	0
SO_x	<10 ppmv	<2.5%v.	0
H_2	<3%v.	Trace	3%v.

Table 3: Example of compositions of CO_2 from a Steam-Methane Reforming plant (Port Arthur)

	PORT ARTHUR SMR – CALIBRATION STREAM COMPOSITION / %	PORT ARTHUR SMR – PERFORMANCE TEST COMPOSITION / %
CO_2	96.8	98.11
CH_4	0.605	1.08
N_2	1.736	0.46
CO	0.163	0.20
H_2	0.606	0.16

Integrity threats and key gaps

Internal corrosion

The most significant integrity threat in a CO_2 pipeline is the occurrence of internal corrosion if a separate aqueous phase drops-out during transportation. There are two specific cases by which this can occur; this is illustrated in Figure 1 [4][5][6][7][8][9][10]:

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- **Without SO_x and NO_x**[1]- water is above its solubility limit in the specific CO_2 stream (in consideration of the type and level of contaminants)
- **In the presence of SO_x and NO_x**, formation and dropout of strong acids, i.e. sulphuric H_2SO_4 and nitric acids HNO_3, and the potential precipitation of elemental sulphur. This can happen below the actual water solubility limit.

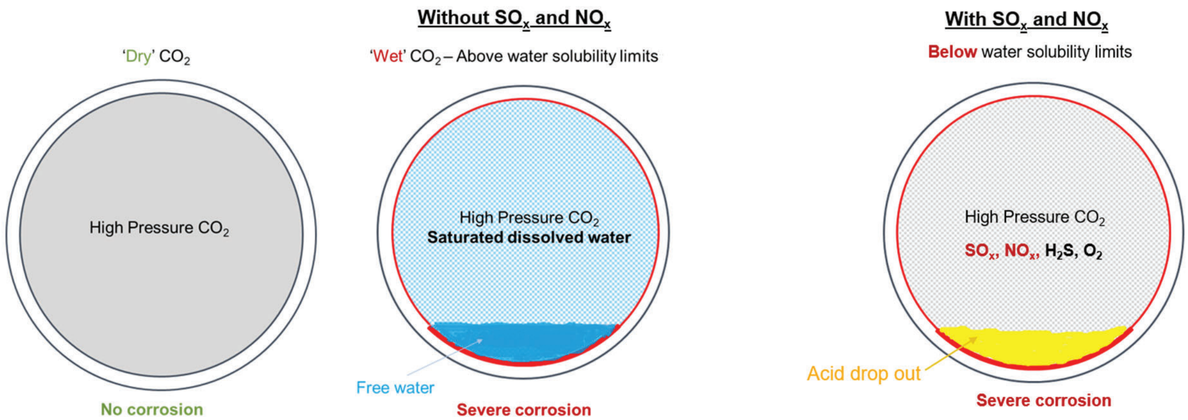

Figure 1: Cases of occurrence of internal corrosion during CO_2 transportation

Localised corrosion (pitting) and more uniform corrosion (resulting from clusters of pitting) could be expected as illustrated in Figure 2 [11][12].

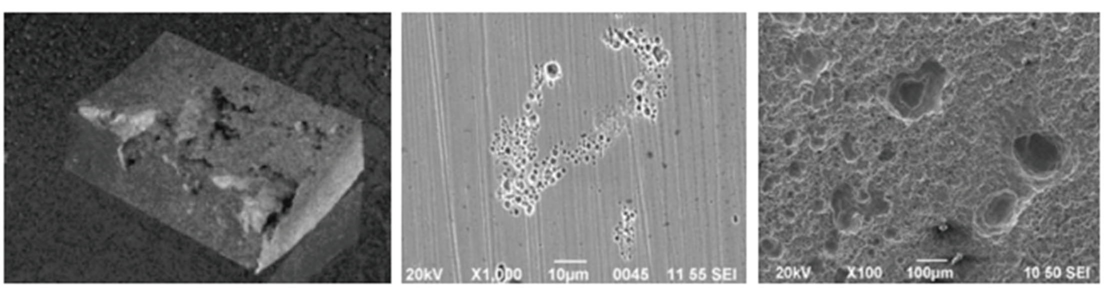

Figure 2: Morphologies of volumetric flaws which may be seen during CO_2 service

Boundaries of corrosion rates have been identified in

Table 4 from published corrosion test data [13] in case of upset (formation of a separate aqueous phase). These are only estimated and may not represent upper or lower bounds; they can widely vary on case by case depending (mainly) on: CO_2 composition, free water volume to surface ratio (severity

[1] Or other potential impurities leading to the formation and drop-out of acids below water solubility limit

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of upset), condensation rate, flow rate, in-take of liquids by CO_2, temperature (and to some extent pressure[2]), duration of exposure to an aqueous phase. In the particular case of CO_2 generated from post-combustion processes, and containing SO_x and NO_x, parameters affecting (i) the formation and solubility of sulphuric acids and nitric acids -e.g. composition of CO_2 (type and levels of all impurities), temperature, and (ii) the corrosivity and pH of the aqueous phase -e.g. water content, chemical composition (acids, alcohols, inorganics), shall also be considered. For example, H_2S and O_2 (in addition to SO_x and NO_x) can favor the formation of HNO_3 and H_2SO_4, while alcohols (methanol) and inorganics (ammonia) can increase the pH of the water and lower corrosivity.

Table 4: Estimated corrosion rates at 10-20°C based on published papers

	Estimated[1] corrosion rates @10-20°C		Industry pipeline experience - corrosion rate
	Severe continuous upset	**Short-term upset (with water hold-up at BOL)**	
Pure CO_2	BOL- 10-20 mm/year	BOL- 0.5 - 1 mm /year[2]	
	Circ - 0.1-0.5 mm/year	Circ – <<0.1 mm/year	
CO_2 <u>without</u> SO_x, NO_x e.g. captured from Natural Gas sources, pre-combustion / SMR	Variations from pure CO_2 expected particularly due to O_2, H_2S. Ranges for pure CO_2 may be considered by default but with caution [2]		0.25-2.5 μm/y[4]
CO_2 with SO_x, NO_x[5] e.g. from post-combustion	BOL - No boundaries– Excessive rates can be expected	BOL - No boundaries – Industry gap	No industry experience of operational pipelines
	Circ – No boundaries - High rates can be expected		

(1) May not be a true upper or lower bounds.

(2) Exposure over 2-3 weeks

(3) Oxygen and H_2S can increase corrosion rates. CO may lower corrosion rates.

(4) US experience of corrosion rates reported on ‘dry’ dense-phase CO_2 pipelines over a period of 12 years

(5) Or without other impurities e.g. HCl, HCN leading to the formation of acids

It is clear that a continuous drop-out of an aqueous phase is unwanted, as it will lead to aggressive and unmanageable corrosion rates, and must be prevented by application of adequate specifications. The latter is an active industry topic of research and discussion, particularly in the presence of impurities such as SO_x and NO_x [10][14], and it is beyond the scope of this paper. It is nevertheless

[2] CO_2 is in liquid state and hence pressure has a limited to moderate impact on the change in free water chemistry and corrosivity over the pressure range above the critical pressure.

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acknowledged that short-lived operational upsets may happen over a CO_2 pipeline's operational life, particularly in complex hubs with multiple feeders. A key question would be then to define a practical corrosion rate trend (versus time) associated with liquids hold-ups post-upsets, so that a practical integrity management strategy could be practically defined. This is a key gap, particularly in the case of CO_2 captured from post-combustion. It is noted that the gaps in defining corrosion rate boundaries in the presence of impurities for 'upset' conditions are symptomatic of the industry concern shifted towards defining composition and operational limits to prevent the formation and dropout of strong acids below water solubility limits (in a 'pure' system), rather than mimicking extreme upset conditions with free water.

Internal Environmentally Assisted Cracking

Pure CO_2 stream

It is generally discussed that the presence of CO_2 alone is not sufficient to drive the initiation and propagation of Environmentally Assisted Cracking (EAC). However, in the presence of a separate aqueous phase, there could be specific stress conditions for which EAC (in the form of Stress-Corrosion Cracking (SCC)) can be observed.

For example, Hudgins et al. [15] indicate that cracking may be generated on high-strength carbon steel in high-pressure CO_2 environments under extreme stress conditions with relatively long exposure times. At 20 bar, CO_2 failures were produced during exposures of as low as 22 hours on steel materials with a hardness of 34 HRC/320 HV and deformation levels of 115%; the production of cracks was associated with the potential leaching of sulphur from the steel materials.

CO_2-H_2O SCC is an EAC mechanism that has also been practically identified as a failure mode in flexible armours [16]. The phenomenon has been observed to take place notably in severe CO2 environments and high applied stresses (equivalent or over to 100%SMYS) and is a cause of great concern to the flexible pipe industry.

Although these strain, stress and hardness levels are significantly higher than those that would be found in most pipelines, specific cases should be considered where such high stresses (e.g. from geohazards, offshore subsidence) and high-hardness (e.g. hard spots, mechanical damages) may arise for CO_2 transportation.

Impact of contaminants in CO_2 stream

As aforementioned, CO_2 streams from certain sources, like pre-combustion or SMR processes, may contain impurities such as H_2, H_2S and CO; these can be responsible EAC in linepipe steels [17][18].

A key point is that EAC due to H_2 does not necessitate the formation of a free separate aqueous phase, while the latter is a '*must*' in the case of H_2S and CO (Table 5).

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Table 5: Environmentally assisted cracking mechanisms due to the presence of impurities

Impurity	Environmentally - Assisted Cracking	Presence of free separate aqueous phase
H_2	Hydrogen embrittlement Hydrogen Assisted Fatigue	**No requirement**
H_2S	Sulphide Stress Cracking (SSC) Hydrogen-Induced Cracking (HIC)	**Yes - required**
CO	CO-CO_2-H_2O SCC	**Yes - required**

These cracking mechanisms are discussed below.

H_2, Hydrogen Embrittlement and Fatigue

Molecular hydrogen may dissociate into atomic hydrogen, which can then be adsorbed and diffuse into the steel lattice. The presence of atomic hydrogen in the lattice can lead to embrittlement e.g. degradation of toughness, and crack growth of preexisting flaws particularly under dynamic loading (fatigue). Data on this topic remain sparse in the context of CO_2 transportation.

Impact on fracture toughness

Sonke and Zheng [10] suggest that the presence of H_2 is '*expected to have minimal impact*' on the fracture toughness, 'due to expected low concentrations in dense CO_2 transportation'. The authors believe this can be misleading as research [19] on pipeline integrity in gaseous hydrogen blends shows that initial decrease in fracture toughness can be very significant at small amounts[3] of hydrogen. In dense phase transportation, the diffusion and adsorption processes of H_2 to the line pipe surface may not be significantly influenced by pressure (in contrast to gaseous applications[4]), but its impact on hydrogen embrittlement must not be overlooked. This point is further confirmed by the work conducted by Kuo et al [20].

Kuo et al. [20] investigated the effect of hydrogen partial pressure in dense CO_2 stream of various API 5L PSL2 line pipe sour and sweet X60 and X70 grades on fracture toughness. The behavior was benchmarked to an inert environment, and to 100% hydrogen (Table 6).

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[3] As low as 1 bar

[4] In gaseous CO_2 transportation, Hydrogen Embrittlement, and the impact on fracture toughness, due to the presence of hydrogen can be significant at partial pressures as low as 1 bar (or lower), and need to be assessed accordingly to ensure long-term safe pipeline integrity. This is a topic that requires further research in regards to CO_2 transportation.

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Table 6: Environments tested to investigate the effect of Pp H_2 in CO_2 on toughness by Kuo et al [20].

Test Environment	CO_2 pressure (bar)*	Hydrogen pressure (bar)*
Inert		
Hydrogen as an impurity in dense CO_2	160	2
	100	1
	165	3.5
100% hydrogen		165
		245
*Approximative		

Kua et al. [20] reported that for all test specimens the CO_2 and H_2 blend conditions showed a noticeable drop in initiation fracture toughness (K_{Jth}) compared to the inert test condition. The impact could be seen at a hydrogen percentage as low as 1%vol., and the drop was comparable to that in 100% H_2. There could be a hydrogen pressure below which the initiation fracture toughness may not be impacted but results suggest it will be 1 bar.

Of particular interest, the fracture toughness value of the CO_2 and H_2 blend condition increases as the crack extends; the behavior can be observed in the fracture toughness values at 0.2 mm crack extension ($K_{0.2mm}$). This behavior is not seen at the same extent for 100%H_2, for which the fracture toughness trend vs crack extension remains relatively flatter in comparison. A schematic of the results reported by Kua et al is illustrated in Figure 3.

Kua et al. [20] hypothesises that for CO_2 and H_2 blend conditions, there could be insufficient hydrogen flux/concentration at the crack tip to have hydrogen embrittlement effect after the impact on the initiation fracture toughness. As the crack grows, ductile tearing behavior takes over and results to a strong R-curve behavior with higher fracture toughnesses.

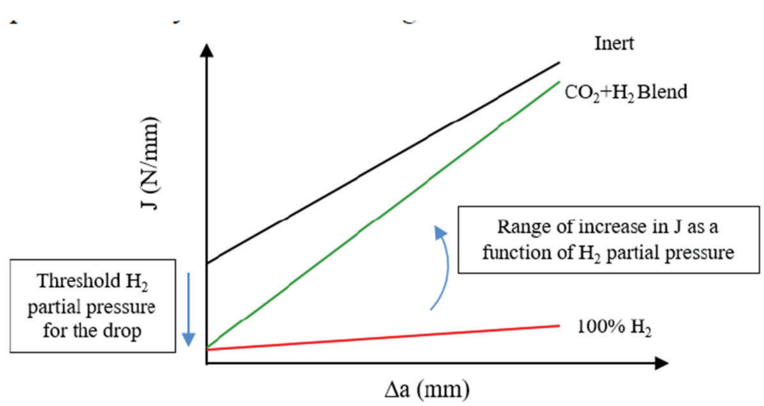

Figure 3: Schematic for the observation of effects of hydrogen on fracture toughness in dense CO_2 by Kuo et al [20].

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Further work and a larger industry experimental dataset is required is needed to reach a wider understanding of the effect on H_2 partial pressure to CO_2 transportation lines. The additional combined effect of H_2S (can also be present, along with H_2, from precombustion / SMR processes) on the fracture toughness behavior shall for example also be considered. Nonetheless these results indicate that the presence of gaseous hydrogen as an impurity can have a major impact on the management of cracks or crack-like flaws in a pipeline transporting dense CO_2. A key question would be to determine what sizes of planar flaws are acceptable for safe operations [21].

Impact on Fatigue Crack Growth Rates

Thodla et Gui [22] investigated the impact of hydrogen on fatigue crack growth rates (FCGR) of a X65 in dense CO_2 for the following conditions: 2 bar H_2 and 100 bar CO_2 (Figure 4). It was reported that albeit FCGRs are multiplied by a factor of 10 compared to in-air conditions at high ΔK, the behavior is comparable (at least for a ΔK_{max} of approximately 50 to 80 $MPa\sqrt{m}$) to the fatigue design basis used for offshore pipelines subject to non-sour service or that of FCGRs in seawater under sacrificial cathodic protection (CP). At low ΔK, the FCGRs at 2 bar H_2 and 100 bar CO_2 are significantly lower. Sonke and Zheng [10] concluded that an impurity limit of up to 1% H_2 (equals 2 bar H_2 in 200 bar operating conditions) seems an acceptable limit for which pipeline design does not require specific adjustments. The dataset remains nevertheless limited and a larger industry experimental dataset is required to reach a more robust statistical picture of the impact of hydrogen concentrations in dense CO_2 on fatigue behavior e.g. Higher concentrations of H_2, linepipes of various grades, microstructures, age. In addition, the combined effect of H_2S should also be considered.

It is noted that, irrespectively to the behavior in dense operations, in *gaseous* CO_2 transportation Hydrogen Assisted Fatigue can be significant at hydrogen partial pressures as low as 1 bar (or lower), and need to be assessed accordingly to ensure long-term safe pipeline integrity.

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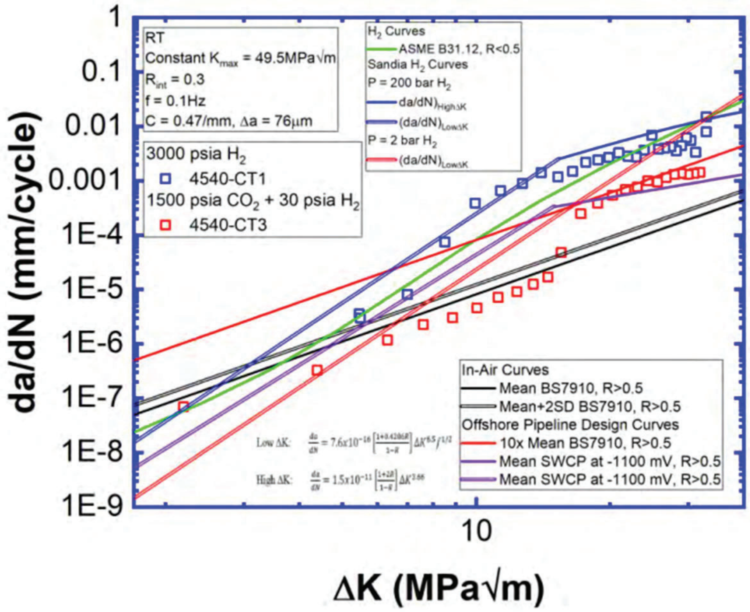

Figure 4: Paris curve of X65 in 200 bar H_2 and in 100 bar CO_2 + 2 bar H_2 at a constant K_{max} of 49.5 MPa√m and decreasing ΔK conditions at 0.1 Hz

H_2S and Sour Cracking

The presence of H_2S can lead to different types of sour cracking, mainly sulphide stress corrosion cracking (SSCC) and hydrogen-induced cracking (HIC). These threats and their respective mitigation requirements have been well documented in the oil and gas industry, especially through the standard NACE[5] MR0175/ISO 15156 [23]. As water upsets should be ideally minimised in CO_2 transportation operations, HIC should not be expected as the mechanism is a rather slow process, which may not be the case for SSCC.

While some have considered that NACE MR0175/ISO 15156 and its limits remain applicable for evaluating SSCC, this may be misleading and there are some major short falls to consider, that impact **[Error! Bookmark not defined.]** its use for dense CO_2 transportation. Key inputs in the aforementioned NACE/ISO standard are H_2S partial pressure (pH_2S) and pH; however:

- The partitioning of H_2S in water from a dense CO_2 phase to water is not expected to be significantly influenced by pressure. The use of partial pressure of H_2S becomes then incorrect. Instead of pH_2S, the use of H_2S concentration in a water phase or a translation to a H_2S content in dense phase CO_2 would be more appropriate
- The pH of a separate water phase in pure dense CO_2 or with impurities is lower (typically 3 or less) than for oil and gas service, and fall outside the experience and data used for the derivation of the standard.

[5] NACE and SSPC are now AMPP, The Association for Materials Protection and Performance. NACE and SSPC products may be obtained through the AMPP Store, https://store.ampp.org

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- Some additional impurities such as HCN, H_2 or leading to the formation of elemental S could increase the susceptibility to SSCC.

Further work is ongoing to identity safe limits for H_2S in CO_2 transport in regards to sour cracking issues. It is important that it is also done in reflection of other impurities that may be present in CO_2 streams. For example some impurities (SO_x, NO_x, O_2) can lead to the formation of strong acids (acidification of pH to 1) and elemental sulphur, which can further increase susceptibility to SSCC; H_2 can also increase embrittlement as discussed above.

CO_2-CO-H_2O Stress Corrosion Cracking

In the 1970s, cracking of carbon steels was observed in environments constituted of wet mixtures of carbon dioxide and carbon monoxide gases, such as those present in coal chemical processing plants, and town-gas manufacture, transport and storage systems. The cracking was attributed to CO_2-CO-H_2O SCC [24] [25], which refers to Stress Corrosion Cracking (SCC) that may occur in pipelines when they transport CO_2 mixed with carbon monoxide and water. Brown [25] and Kowaka and Nagata [24] have demonstrated that transgranular stress corrosion cracking can occur in such conditions. This mechanism is driven by stress, liquid water, and CO levels, with the additional oxygen increasing the susceptibility to SCC (oxygen shifts the corrosion potential in the SCC susceptible region, and accelerates propagation growth rate by weakening 'pseudo-surface passivity'). The SCC mechanism in this system follows the "strain-generated active path" model, where a mono-molecular CO film is formed on the surface of the carbon steel and breaks under stress; local anodic attack ensures and the cycle repeats [25].

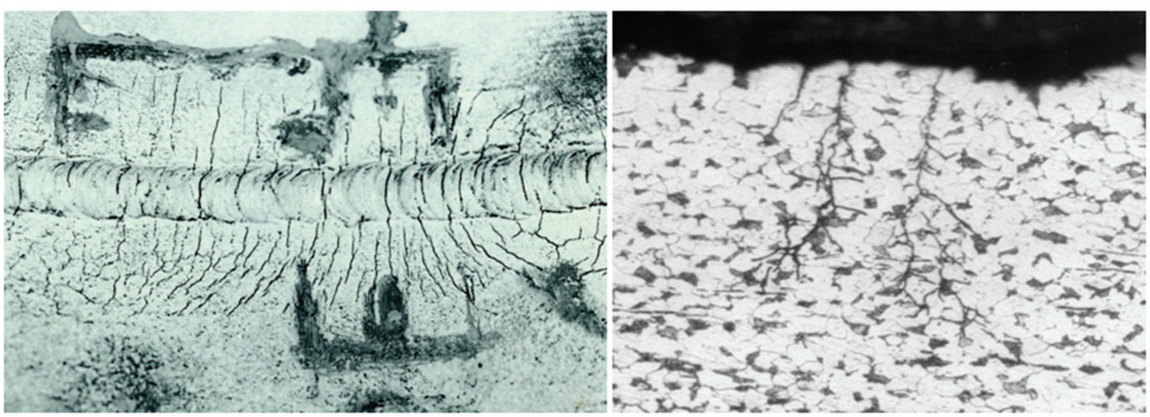

Figure 4: CO_2-CO-H_2O SCC morphologies [17][18]

Experimental evidence mostly comes from tests with low CO_2 pressures (under 20 bar), but research is underway to look at the effect of CO on the occurrence of SCC in dense CO_2 operations.

Wu et al. [26] shows that API 5L X65 can be susceptible to SCC in the presence of CO in dense CO_2. SCC tests were conducted in CO_2 mixture at 30°C and 100 bar with 2.1 bar CO (or 21,000 ppmv) for 31 days; coupons were stressed to 90% of SMYS (four-point bend).

Gonuguntla et al [27]subjected API 5L X65 to a 4-point bend test at lower CO_2 pressures (50 bar) and lower CO concentrations (1000 ppm), applied stresses of 90%SMYS, and showed no cracks. The

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investigators concluded that, "*The tests clearly indicate that the risk of CO-CO_2 cracking is not significant up to the concentrations tested*". This was used in the derivation of the AMPP 21532-2023 guidance, which limits CO to 1000 ppm to avoid CO_2-CO-H_2O SCC

Nevertheless, and as aforementioned, the additional potential presence of oxygen in the streams (even at trace levels) must be considered; oxygen can lower the CO limit for SCC. At 7000 ppm CO and 100 ppm O_2, Wu et al. [26] reported cracking in dense CO_2. Further experimental work is required to address acceptable limits and boundaries of susceptibilities in line to design and operational regimes applicable to a CO_2 transportation pipeline over its life cycle. The presence of other impurities should also be considered.

In-Line Inspections

We discussed that the most major threat (specifically related to CO_2) is the occurrence of internal corrosion (general corrosion and pitting), but EAC mechanisms (cracks) should also be considered. The deployment of metal loss ILI and crack ILI tools will be therefore required as part of future integrity management planning.

This will as a minimum require that baseline surveys are conducted as part of the conversion strategies, to allow the monitoring of defect growth and the determination of mechanism growth rates for remaining life studies. To ensure that any growth is accurately measured it is normally recommended that the same technology be used for the baseline survey and any subsequent inspections. Choice of ILI technology is therefore key.

Although the dense CO_2 phase reacts like a liquid with regards to some of its physical properties, the application of liquid coupled ultrasonic testing (UT) is not possible with the required accuracy. This is primarily due to the high level of variation in the density, sound velocity and impedance that occurs in dense phase or supercritical fluids with any change in temperature and pressure, which is in avoidable in a dynamic pipeline environment. These variations affect the behavior of the UT beam, leading to unpredictable and unreliable inspection results.

Corrosion detection technologies

<u>Magnetic flux leakage</u>

Due to the unsuitability of ultrasonic technology for use in CO_2, magnetic flux leakage (MFL) is the most viable in-line technology for corrosion detection and sizing. One of the most widely used and popular ILI technologies, MFL is robust, proven, and can be adapted to achieve a range of specifications by orienting the magnetic field either axially (MFL-A) or circumferentially (MFL-C), or using higher resolution sensors, as in ROSEN's MFL-A Ultra. A range of tool configurations are available across a wide range of diameters to facilitate inspection through multi-diameter pipelines, wyes and other challenging geometries.

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Because MFL technology relies on magnetic saturation of the pipe wall, as shown in Figure 5, heavy wall thicknesses can pose a challenge; if pipe wall saturation is not achieved, then detection and sizing of metal loss features may not meet the published specifications.

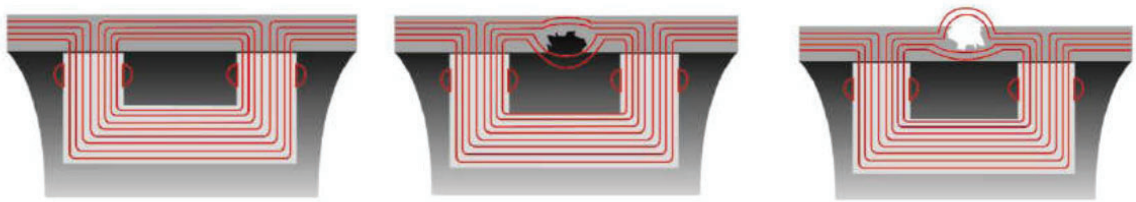

Figure 5: MFL principle; defect-free pipe (left), internal defect (centre) and external defect (right)

ROSEN's MFL-A tools are capable of detecting and sizing general corrosion and pitting defects with depths of 10% of the pipe wall, with MFL-A Ultra tools capable of detecting and sizing general corrosion with depths of 5% of the pipe wall and pinholes with depths of 10% of the pipe wall. Provided that the pipeline and operating parameters are within the acceptable range for inspection, the performance specification should allow for detection and sizing of any critical pitting and general corrosion features present.

<u>Internal Eddy Current (IEC)</u>

ROSEN's Internal Eddy Current (IEC) tools use a combination of high-resolution measurement arms and eddy current sensors to achieve detection and sizing of shallow internal metal loss features as well as geometry features such as dents.

This technology is not affected by heavy wall pipe, although depth sizing is not possible beyond a defect depth of 10 mm. Depending on the wall thicknesses present, detection and sizing of some pinhole features may be possible.

Combining IEC and MFL-A technology provides enhanced detection and sizing of internal metal loss features including pinholes.

Crack detection technologies

As ultrasonic crack detection technologies are not compatible with dense CO_2, electromagnetic acoustic transducer (EMAT) technology is considered the only viable technology for use in CO_2 pipelines. A key limitation of EMAT technology is that it is typically not well suited to "heavy wall" pipe, which is prohibitive for many CO_2 pipelines.

Flooding a pipeline or running ILI tools in a liquid batch to provide the required conditions for ultrasonic crack detection may be the only option if crack detection ILI is required, however, there are risks associated with introducing contaminants such as water or MEG into the pipeline, which have been discussed previously.

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Pigging in CO_2

The following considerations apply not only to ILI tools but also to mechanical cleaning pigs that are typically run prior to the ILI tool, to prove the pipeline bore and remove any debris.

<u>Pressure</u>

Dense CO_2 is maintained at above the critical pressure of ~75 bar and is often transported at significantly higher pressures for efficiency. ILI tools can typically operate at up to 100-150 bar in "standard" configurations, but specialised configurations can be created for operation at higher pressures.

As in all gases, higher pressures are operationally preferable to low pressures due to the increased stability in terms of pig dynamics within the pipeline; dense phase CO_2 provides conditions close to those of running in liquid, meaning that speed variations are expected to be minimal and are not of concern. Additionally, CO_2 has a higher density than natural gas, further increasing the stability of the run conditions for any pigs.

On depressurization, the density of dense CO_2 will decrease rapidly as it changes to gas phase. As all the voids and porous materials on the pig will be saturated with dense CO_2, the rapid decompression results in bubbling, swelling and splitting of cable sheaths, polyurethane parts and sealants, as shown in Figure 5.

Figure 5: Cable before (L) and after (R) CO2 exposure testing

Due to the increased damage following decompression, extensive refurbishment may be needed. Inspecting for damage and replacing affected parts will be required following each run to ensure tool integrity; this applies to both cleaning and inspection pigs.

<u>Temperature</u>

The Joule-Thomson effect causes a significant temperature drop on depressurisation for CO_2, with the potential to reach below -20°C. At extreme low temperatures the batteries and electronics of ILI tools may be affected.

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Due to the lack of test data to date, temperature drop should be limited where possible by depressurising at a controlled rate.

Wear

Depending on the purity of the CO_2 being transported, it has the potential to be an extremely dry medium in its purest form, resulting in potentially high wear conditions for cleaning pigs and ILI tools.

As pigs are typically driven by polyurethane discs or cups, the setup of the pigs and the construction of drive discs and cups must be tailored to ensure the pig doesn't lose drive and stall in the pipeline. Special measures may include adding additional modules, adding additional discs or cups, embedding metal strips within the cups, and adding metallic ring brushes to support and centralise the pig in the pipeline.

Pipeline length and run speed

Due to the location of many proposed CCUS pipelines, they may have to be long to transport CO_2 to the storage location. The initial flow rates may also be low, leading to long, slow pigging operations. This will compound the challenges of protecting pigs against wear and introduces the challenge of providing sufficient battery life for the selected ILI technologies.

Initial low flow rates may favor the functionality of MFL technology, however, as the optimum speed range for this technology in heavy walled pipe is typically ~1 m/s. Figure 6 shows a typical wall thickness vs. velocity plot for MFL, illustrating the correlation between pipe wall saturation and pig speed. During later operational life, if flow rates are expected to increase, they may have to be controlled during ILI operations to ensure the data is not degraded.

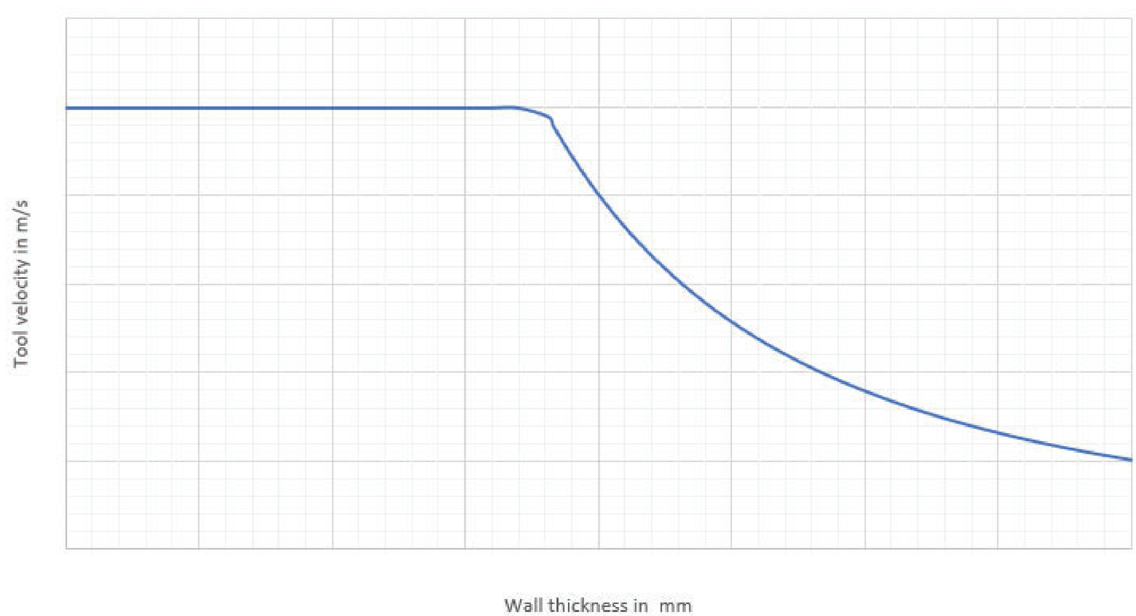

Figure 6: Wall thickness vs. velocity

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Summary of key challenges for pigging in CO_2

- Dense CO_2 is generally not compatible with ultrasonic technologies due to the high sensitivity to variations in temperature and pressure,
- Purpose-built CO_2 pipelines are often designed with heavy wall thicknesses, posing a challenge to MFL and EMAT technologies,
- The dry medium and pipeline length must be considered; cleaning and ILI tools must be designed for wear resistance,
- Run speed may be critical for MFL in heavy walled pipes,
- Extensive pig refurbishment may be needed between runs due to explosive decompression.

Testing

ROSEN have conducted extensive in-house testing of pig components and materials in high pressure dense CO_2, including cables, sensors and polyurethane samples, with some examples shown in Figure 7. The testing carried out was over a 24-hour period, and the effects were monitored during and after, with the functionality of the components tested afterwards where possible. The principal findings were that, while damage occurs on decompression, no degradation was observed while at pressure, with an additional observation that some damage was only apparent after more than an hour following depressurization due to the time taken for the CO_2 to migrate through the material. It is therefore likely that more extensive tool refurbishment will be needed between dense CO_2 runs to account for the decompression damage, however the integrity and functionality of tools while at pressure is not considered to be a significant concern.

Figure 7: Cables after CO2 exposure testing

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Some further testing is required to fully understand the impact of CO_2 on other materials such as adhesives.

Track record

ROSEN have experience of pigging in supercritical/dense CO_2 in diameters from 8” to 30”, in pipelines >200 km in length and in countries around the world. This further proves the robustness of MFL and IEC technology in this challenging medium.

Conclusions

1. There are specific time-dependant internal integrity threats associated with the pipeline transportation of man-made CO_2. These could lead to internal volumetric metal losses and planar (crack) flaws.
2. The majority of these threats (except in the case of gaseous H_2) necessitate a sperate aqueous phase and should be addressed with deploying suitable target specifications. The latter is an ongoing active industry topic of research. It is also nevertheless acknowledged that short-lived operational upsets may happen over a CO_2 pipeline’s operational life, particularly in complex hubs with multiple feeders.
3. The presence of gaseous hydrogen as an impurity can have a major impact on the management of cracks or crack-like flaws in a pipeline transporting dense CO_2. A key question would be to determine what sizes of planar flaws are acceptable for safe operations. The combined effect of H_2S shall be considered (and for fatigue analysis also).
4. There are industry gaps for the occurrence of cracking in the presence of H_2S and CO in dense CO_2 transportation. Further work is ongoing to identity safe limits. It is important that it is also done in reflection of other impurities that may be present in CO_2 streams.
5. Existing, proven in-line inspection technologies can be used to detect, size and monitor corrosion and cracking that may occur as a result of CO_2 service. The key challenges are the incompatibility of dense CO_2 with ultrasonic technologies, and the heavy wall thicknesses of CO_2 pipelines that may rule out EMAT and push the limits of MFL technology.
6. Providing the wall thicknesses are within range for the technologies selected, and the run speed can be controlled, CO_2 as a medium does not present a threat to inspection data collection, although extensive post-run tool refurbishments are likely to be needed. Testing is ongoing to confirm the resilience of all materials during long-term exposure to dense CO_2, but testing to date has not shown any incompatibilities.
7. Configurations of cleaning pigs and ILI tools and deployment planning for both should take into consideration the potential for long run times, high wear, severe damage due to explosive decompression, and potential damage due to extreme low temperatures.

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