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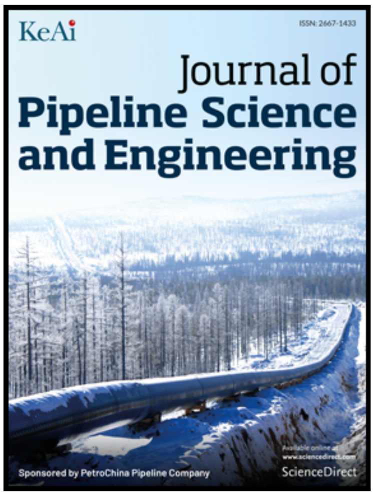

Blending hydrogen in existing natural gas pipelines: integrity consequences from a fitness for service perspective

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Blending hydrogen in existing natural gas pipelines: integrity consequences from a fitness for service perspective

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ABSTRACT

Blending hydrogen in existing natural gas pipelines compromises steel integrity because it increases fatigue crack growth, promotes subcritical cracking and decreases fracture toughness. In this regard, several laboratories reported that the fracture toughness measured in a hydrogen containing gaseous atmosphere, K_{IH}, can be 50% or less than K_{IC}, the fracture toughness measured in air. From a pipeline integrity perspective, fracture mechanics predicts that injecting hydrogen in a natural gas pipeline decreases the failure pressure and the size of the critical flaw at a given pressure level. For a pipeline with a given flaw size, as shown in this work, the effect of hydrogen embrittlement (HE) in the predicted failure pressure is largest when failure occurs by brittle fracture. The HE effect on failure pressure diminishes with a decreasing crack size or increasing fracture toughness. The safety margin after a successful hydrostatic test is reduced and therefore the time between hydrotests should be decreased. In this work, all those effects were quantified using a crack assessment methodology (level 2, API 579-ASME FFS) considering literature values for K_{IH} and K_{IC} reported for an API 5L X52 pipeline steel. To characterize different scenarios, various crack sizes were assumed, including a small crack with a size close to the detection limit of current in-line inspection techniques and a larger crack that represents the largest crack size that could survive a hydrotest to 100% of the steel specified minimum yield stress. The implications of a smaller failure pressure and smaller critical crack size on pipeline integrity are discussed in this paper.

KEY WORDS: Pipeline; fracture toughness; hydrogen embrittlement; blending; integrity; flaw; hydrotest.

INTRODUCTION

Climate change concerns foster the use of hydrogen as an energy vector. Dedicated hydrogen pipelines or retrofitted natural gas pipelines are economic alternatives for transporting hydrogen [1]. ASME code B31.12 [2] addresses materials selection and the design, fabrication and testing of dedicated hydrogen pipelines, including instructions for retrofitting existing pipelines originally constructed for a different service (natural gas or liquid hydrocarbons). That code applies for hydrogen contents in the gas phase higher than 10% in volume. Despite this 10% limit, it is now accepted that carbon steel mechanical properties could be degraded even when the hydrogen content in the blend is below this threshold value [3-6]. This means that prior to blending hydrogen in existing natural gas pipelines, which is attractive because it partially decarbonates the natural gas, an integrity assessment must be conducted so that safe operation is guaranteed.

Hydrogen decreases pipeline steel ductility and fracture toughness, it favors subcritical cracking and increases the fatigue crack growth rate (FCGR), as reviewed elsewhere [7- 11]. Subcritical cracking is expected in zones with hardness above 98 HRB (228 HV) [11]. For a pipeline, those high values of hardness are expected, for example, near welds of vintage C-

Mn steels or in cold-worked zones. The increase in FCGR by hydrogen is relevant when the pipeline is cyclically loaded. The methodology for estimating residual life is described in KD-10 article of ASME BPVC, Section VIII, Division 3 [12]. Some examples of such calculations are available in the literature [3, 5, 6, 13, 14]. The present work addresses some effects on pipeline integrity related to the decrease in fracture toughness.

Fracture toughness (K_{IC}) can be interpreted as the material resistance to crack propagation. It is a function of steel composition, microstructure, and temperature. For ductile materials like pipeline steels, K_{IC} is obtained from measurements of J integral or from the value of the crack-tip opening displacement (CTOD) at the onset of crack extension [15,16]. In a pipeline pressurized with natural gas, the material resistance to crack extension is K_{IC}, because methane is considered an inert gas with respect to crack propagation [17]. In a pipeline that transports pure hydrogen or a blend, the key parameter is K_{IH}, the hydrogen affected fracture toughness. At a given temperature, K_{IH} depends on material grade, microstructure, and hydrogen partial pressure. The decrease in fracture toughness is caused by hydrogen embrittlement (HE) mechanisms. Depending on hydrogen concentration in the metal, steel grade and microstructure, hydrogen enhanced decohesion (HEDE), localized enhanced localized plasticity (HELP) or a synergistic HELP+HEDE mechanism [18-20] can explain the decrease in fracture toughness. Recent results on pipeline steels [3-5, 21] conclude that when the fracture toughness is measured in hydrogen gas (K_{IH}) its value ranges from 46% to 73% of $K_{IC.}$ Those results were obtained in pure hydrogen and mixtures, at total pressures representatives of transmission pipelines, and for a wide range of grades of pipeline steels admitted by ASME B31.12 code, ranging from API 5L X42 up to API 5L X70. The decrease in fracture toughness persists even for very low H_2 partial pressures [3-5]. The reduction in fracture toughness could be larger for higher grade steels, for example, for API 5L X80, K_{IH} in pure hydrogen at 30 MPa is 6% of K_{IC} [21].

Fracture toughness is a key property for existing pipelines because all of them have cracks or defects formed during service and/or fabrication. Common examples are lack of fusion in welds and external cracks caused by stress corrosion cracking [22]. Current alternatives for crack management of pipelines include direct assessment [23], in-line inspection [24], and hydraulic testing [25], as reviewed elsewhere [26]. Direct assessment is a systematic methodology for prioritizing digging inspections based on the material, environment and stress level dependences of stress corrosion cracking processes. In-line inspection (ILI) involves the use of inspection pigs, running on the inside of the pipeline during scheduled maintenance examination. Pigs with Electro-Magnetic Acoustic Transducer (EMAT) are the most promising technology for crack detection [24]. Hydraulic testing is a destructive alternative for crack detection. The pipeline is shut down and pressurized with water above the operating pressure. This causes failure if defects with a critical size are present but provides no information about subcritical defects [26]. If the pipe fails during a hydrostatic test, the pipe segment is removed, a new segment is welded in place, and the pipeline is retested until the hydrotest is successful. The decrease in fracture toughness by hydrogen has important consequences on the available crack management alternatives, as will be discussed in this work.

According to ASME B31.12 code [2], hydrogen effects in materials could be addressed by using safety factors more conservative than for natural gas service, or by a fractomechanic analysis using hydrogen affected fracture toughness and crack growth rate. Those alternatives are presented as prescriptive and performance-based design methods. The performance-based design method is attractive because it would allow an operator to transport a blend in a given pipeline without a pressure derating. In this regard, it is recalled that hydrogen has 1/3 of the energy density of natural gas, so derating a pipeline would further compromise the energy transport capacity of the pipeline. The performance-based design method requires measuring fracture toughness with either the constant load or constant crack mount opening displacement alternatives presented in ASTM E1681 (2020) [27]. The hydrogen affected fracture toughness must be above the stress applied stress intensity factor considering operating pressure, pipeline dimensions and defect sizes, and also above 50 ksi.in$^{1/2}$ (55 MPa.m$^{1/2}$). Incidentally, this 50 ksi.in$^{1/2}$ threshold has been interpreted as a minimum fracture toughness required for suitability of steels for hydrogen service [28, 29]. However, the fracture mechanics evaluation involves assessing not only the hydrogen affected material properties but also the stability of defects in the pipeline in the new service.

Considering that the base metal of pipeline materials has ductile behavior even when tested in hydrogen gas, integrity assessments of pipelines with cracks require considering the possibility of elastoplastic fracture and plastic collapse [30]. The failure assessment diagram (FAD) described in API 579-1/ASME FFS-1 [31] estimates the mode (brittle fracture, elastoplastic fracture or plastic collapse) and the conditions for the onset of failure by two parameters, related to the reference stress (σ_{ref}) and stress intensity factor (K). The methodology is also known as level 2 analysis for crack assessment. Pluvinage et al. [21] and Andrews et al. [32] analyzed the effect of blends or pure hydrogen in the integrity of pipelines with various defects, including loss of metal by corrosion, gouges, dents and cracks. Cracks were internal and with semielliptical shape [21], with a defect depth over thickness ratio (a/t) that ranged from 0.1 to 0.5. The authors showed that the safety factor, defined as the ratio of failure pressure over maximum allowable operating pressure ($f=P_{fail}/MAOP$), decreased with an increase in defect size or MAOP. Upon a hydrogen injection in the pipeline, the safety factor decreased by up to 20%. Bouledroua et al. [33] used the FAD approach to estimate the remaining safety factor after a pressure surge caused by a rapid closure of a valve, in a flawed pipeline that transports hydrogen gas. The synergistic effects of hydrogen embrittlement and pressure increase by the transient gas flow resulted in a decrease in safety factor of up to 35%.

Hydrogen blending in an existing natural gas pipeline is challenging because there are several damage mechanisms that could have been active since the pipeline was commissioned. These include corrosion, stress corrosion cracking, HE by hydrogen absorption from corrosion reactions, microbiologically induced corrosion and corrosion fatigue [22, 34]. The scope of this paper is limited to crack like defects. The purpose of the paper is to quantify the effect of the decrease in fracture toughness by hydrogen on three important parameters for assessing the integrity of a flawed pipeline. Those parameters are the burst or failure pressure [35, 36], the critical flaw size, i.e. the minimum crack size that would exhibit unstable propagation at a given pressure level, and the remaining life after a hydrotest. Flaws were sized according to detection limits of current in-line-inspection techniques and hydraulic testing. Pressure levels of pipelines were selected according to ASME B31.12 [2] allowable operating stress level and guidelines for hydrostatic testing [25].

THEORY/CALCULATION

The level 2 [31] crack assessment with the FAD methodology allows to estimate if cracks propagate from the tip of a given defect, for a pipeline of known geometry, internal pressure and material properties. A curve and its closed form expression are available in API 579-1/ASME FFS-1 [31]. This curve (Figure 1) limits a region where the pipeline is safe, while failure is predicted if the point falls outside this region. The methodology requires calculation of the ordinate and abscissa of the assessment point according to

$$L_r = \frac{\sigma_{ref}}{S_y} \quad K_r = \frac{K}{K_{IC}}$$ **Equation 1**

Where σ_{ref} is the reference stress, related to stress in the uncracked ligament [15] and K is the applied stress intensity factor, related to the driving force for crack advance. S_y is the yield stress and it is insensitive to hydrogen, according to slow strain rate tests [8]. Notice that in an H_2 containing environment, K_{IC} should be replaced by K_{IH} [30]. Once the coordinates L_r and K_r of the assessment point are calculated, safe or failure condition can be predicted. Both L_r and K_r increase proportionally with operating pressure, hence, loading paths of flawed pipelines are lines that pass through the origin [37]. The failure pressure (P_{fail}) is defined as the pressure where this line intersects with the FAD curve (see Fig 1).

Equation 1 is valid for a component that is only under primary stresses, like those caused by the internal pressure of a pipeline or external loads. If secondary stresses (developed by the constraint of adjacent parts or by self-constraint of a component) or residual stresses are present, details in API 579-1/ASME FFS-1 [31] should be followed. This work considers only primary stresses due to the constant pressure of internal fluids (natural gas, a hydrogen blend, or water used in a hydrotest).

For simple components (like bars, plates, spherical and cylindrical shells) K and σ_{ref} can be calculated from equations listed in API 579-1/ASME FFS-1 [31] for different crack configurations (external, internal, embedded, and in different orientations with respect to component axis). This work analyzed axially oriented flaws nucleated on the external surface of cylindrical shells. Axial flaws are perpendicular to the hoop direction, the one with largest principal stress on pressurized cylindrical shells. The cracks are in the external surface because for pipelines carrying dry natural gas, external stress corrosion cracking in the soil environment is a common failure mode [22]. The expressions recommended by API 579-1/ASME FFS-1 [31] for calculating σ_{ref} and K as a function of pipeline and flaw size are not listed as closed-formed expressions. The required coefficients to perform such calculations are available in various tables listed in API 579-1/ASME FFS-1 [31]. To show the integrity effects of the decreased fracture toughness in hydrogen, a particular case (see parameters in Table 1) is presented. The equations required to solve the case selected are coded in a spreadsheet available on the web [38].

Steel grade, mechanical properties and pipeline thickness and diameter are typical for western existing pipelines, Table 1. Yield strength (S_y) was considered equal to the grade SMYS (specified minimum yield strength). The elliptical surface flaws are characterized by the length (2c) and depth (a). Flaw #1 is a small elliptic flaw, which has a 90% POD (probability of detection) with commercially available ILI-EMAT technology [24]. Iterating with the spreadsheet, the maximum crack size of a flaw, with the same aspect ratio as flaw 1 (ratio of crack length to depth), that would survive a hydrotest at 100% SMYS was calculated and listed as Flaw #2. Flaw #3 has the highest depth possible before the surface crack must be recategorized as a through thickness flaw (a/t=0.8). Its length is such that it represents a critical flaw for a pipeline pressurized at 72% SMYS with natural gas and was calculated iterating with the spreadsheet. Flaw #4 has the same aspect ratio than flaw #1, and a depth equal to 75% of thickness. It represents a critical flaw in a natural gas + hydrogen blend, using K_{IH} instead of K_{IC} in the spreadsheet. The analysis includes a through crack (Flaw #5), with the same aspect ratio than flaw #1. The adopted values of K_{IC} and K_{IH} were recently reported by Ronevich and San Marchi [3] for a microalloyed API 5L X52 in air and in a 3% H_2 + N_2 mixture at 21 MPa.

Notice that an internal pressure such that the hoop stress (σ_h) reaches 72% SMYS represents the situation of many existing natural gas pipelines, that is, under location class 1, division 2 of ASME B31.8 [39]. For the pipeline with the dimensions detailed in table 1, this represents a MAOP= 5.87 MPa (851 psi). It is also the maximum allowable stress level accepted for hydrogen pipelines according to ASME B31.12 code [2], using the performance-based approach. A hydrotest to 100% SMYS is a common practice according to ASME B31.8s [40], and for a pipeline limited to 72% SMYS, it represents a pressure equal to 1.39 MAOP (8.14 MPa).

RESULTS

For a flawed pipeline, both σ_{ref} and K are proportional to pressure inside the pipeline, Fig. 1. As pressure increases, distance from the origin increases in each line in Fig. 1. For each studied condition, the P_{fail} is presented in table 2. The zone where the curve is crossed defines the mode of failure. Flaw #1 fails by plastic collapse at the same pressure level in natural gas and in the hydrogen blend. The slope of the assessment lines increases with the crack size (flaw #1 vs. flaw #5). Flaw #5 fails by elastoplastic fracture, and the failure pressure in hydrogen blend is smaller than in natural gas. A decrease in fracture toughness by hydrogen embrittlement increases the ordinate of the assessment point, and hence the slope of the lines, in accord with literature results [21, 30, 33, 41]. This reduces P_{fail} and can change the mode of failure, Fig. 1, favoring brittle fracture. The exception to this rule is when failure occurs by plastic collapse. Plastic collapse is controlled by S_y, not fracture toughness [42]. Recall that S_y is not reduced in gaseous hydrogen [8].

Table 1. Parameters selected for calculations performed in this work.

Parameter		**Value**		**Comments**
Steel grade		API 5L X52		Common grade in existing western pipelines
S_y		360 MPa (52 ksi)		Within PSL 2 specifications in API 5L [43]
UTS		483 MPa (70 ksi)		
Outside Diameter (OD)		558.8 mm (22 in)		
Thickness (t)		6.35 mm (0.25 in)		
Flaw size		a (depth, mm)	2c (length, mm)	
External semielliptical flaws	**#1**	2	40	Crack that has a 90% POD with ILI-EMAT [24].
	#2	4.13	82.6	A flaw with the same aspect ratio than flaw #1, whose size is the maximum that would survive a hydrotest at 100% SMYS in the case under analysis
	#3	5.08	159	A critical flaw size in the natural gas pipeline pressurized to 72% SMYS, with a depth equal to 80% of t
	#4	4.76	95.3	A flaw with the same aspect ratio than flaw #1, and a depth equal to 75% t. It represents a critical flaw in a natural gas + hydrogen blend.
Through crack	**#5**	6.35 mm	127 mm	A through crack with the same aspect ratio than flaw #1
K_{IC}		300 MPa.m$^{1/2}$ (273 ksi.in$^{1/2}$)		In air [3]
K_{IH}		140 MPa.m$^{1/2}$ (127 ksi.in$^{1/2}$)		In a 3% H_2 + N_2 blend at 21 MPa total pressure [3].

Decreased Failure Pressure in Hydrogen Service

Failure pressure has a non-linear dependence with fracture toughness [42], Fig. 2. This figure was constructed with the spreadsheet for flaw #1 and using the rest of the parameters detailed in table 1. Notice that for brittle failure, failure pressure (P_{fail}) in H_2 decreases linearly with fracture toughness, in accord with linear elastic fracture mechanics predictions. In this region, failure pressure in hydrogen service is reduced proportionally to the decrease in the fracture toughness by hydrogen. The impact of a lower fracture toughness in H_2 in P_{fail} (mathematically, the slope in Fig. 2) is smaller if failure occurs in the elastoplastic regime, and P_{fail} is independent of fracture toughness if failure occurs by plastic collapse. At this zone, steel strength controls failure. In other words, the FAD approach predicts that, for a flawed pipeline of a given grade, size and with known defect sizes and geometries, there exists a threshold K_{IH}, called K_{IH}* in Fig. 2, above which the failure pressure of the pipeline pressurized with H_2 is the same than the failure pressure in an inert gas. If K_{IH}> K_{IH}*, the pipeline can accept a hydrogen blend and there would not be any integrity reason to decrease the total operating pressure. The safety factor at the pipeline MAOP, f= P_{fail}/MAOP, is the same under both services, because P_{fail} is the same, table 2. Notice that the K_{IH}* for the crack shown in Fig. 2 is lower (but close) to 127 ksi.in$^{1/2}$, the actual value of K_{IH} for an API 5L X52 with 3% H_2 at 21 MPa [3]. For K_{IH}< K_{IH}*, the safety factor in hydrogen decreases because P_{fail} in H_2 service is smaller than P_{fail} in natural gas. If it is desired to operate the pipeline at the same safety factor in the hydrogen blend than in natural gas, then the MAOP in hydrogen blend should be reduced by the same percentage than the reduction in safety factor, table 2.

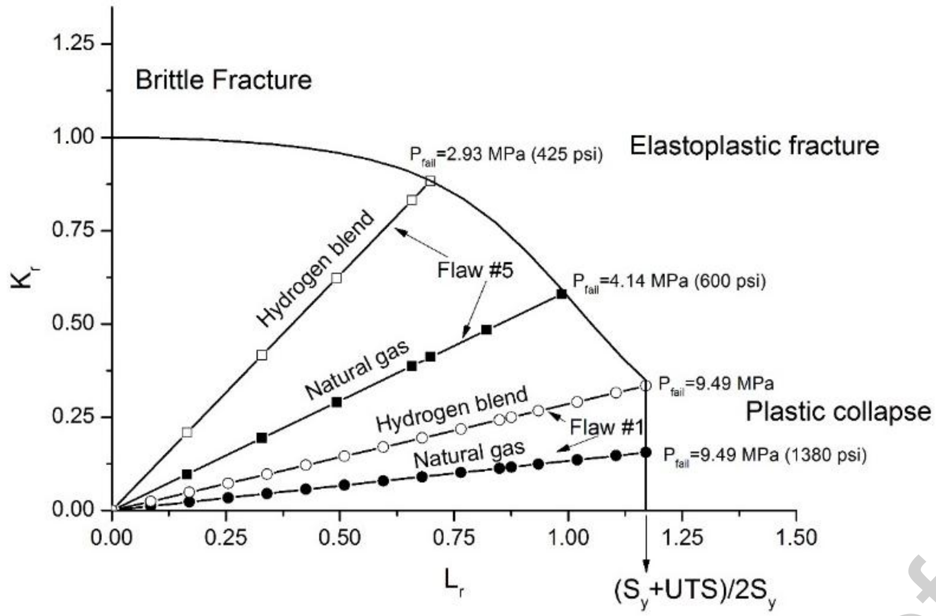

Fig. 1. Failure assessment diagram, showing the effect of fracture toughness on P_{fail}, for a pipeline with parameters detailed in table 1.

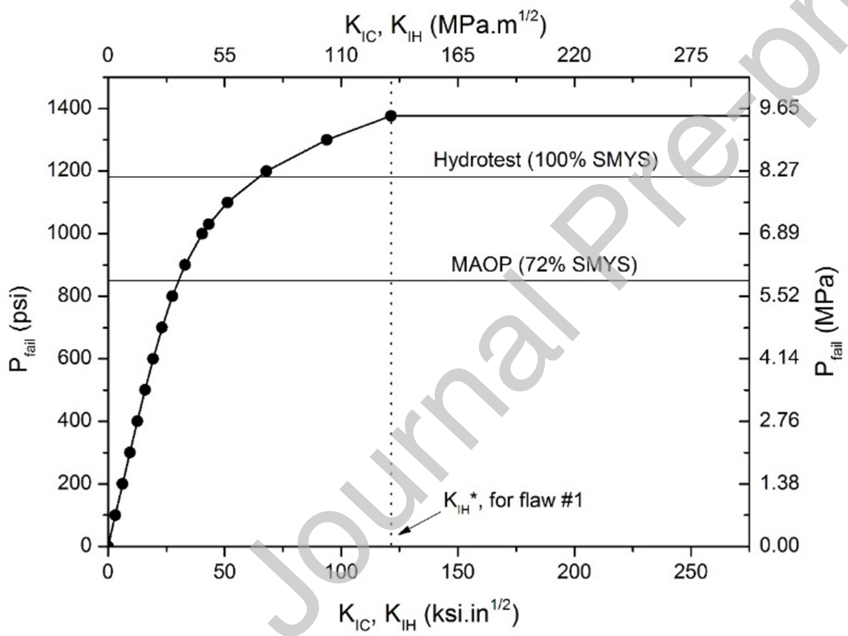

Fig. 2. Failure pressure of a pipeline with flaw #1 vs. fracture toughness, calculated according to FAD level 2 analysis [31], and using parameters shown in table 1. K_{IH}* represents the minimum hydrogen affected fracture toughness above which failure occurs by plastic collapse.

The scenario where K_{IH}>K_{IH}* described in the previous paragraph represents a somewhat favorable situation, because the flaw had a small size and was located in the base metal of a modern, microalloyed pipeline steel. If the flaw had been in the longitudinal or circumferential weld, a lower value for K_{IH} should have been used [44]. Vintage steels have higher carbon, manganese, sulfur and phosphorus and lower fracture toughness [44]. Furthermore, even for a pipeline that was just inspected with ILI-EMAT, there is a finite probability that cracks with a size greater than the one considered were undetected. Finally, a larger flaw would have a larger K_{IH}* value. For example, for flaw size #5, the calculated K_{IH}* is greater than 500 MPa.m$^{1/2}$, well above the expected hydrogen affected fracture toughness of pipeline steels. Consequently, the K_{IH}*, just like any other “threshold” related to environmentally assisted cracking [45], is dependent on the values of the rest of the variables that control the cracking process, and is applicable under those conditions.

Table 2. Failure pressure of flaws and safety factors when MAOP=5.87 MPa for service in natural gas and hydrogen blend. Pipeline and flaw dimensions as detailed in table 1.

	Failure pressure, P_{fail} MPa (psi)		Decrease %	Safety factor, f, at σ_h=72% SMYS (MAOP=5.87 MPa = 851 psi)		Decrease %
	Natural gas	3% H_2 blend		Natural gas	3% H_2 blend	
Flaw #1	9.49 (1380)	9.49 (1380)	0	1.62	1.62	0
Flaw #2	8.14 (1180)	6.76 (980)	17	1.39	1.15	17
Flaw #3	5.87 (851)	4.60 (667)	22	1.00	fail	-
Flaw #4	7.31 (1060)	5.87 (851)	20	1.25	1.00	20
Flaw #5	4.14 (600)	2.93 (425)	29	fail	fail	-

Smaller Critical Flaw Size in Hydrogen Service

Fig. 3 plots the failure pressure of all flaws listed in table 1 vs. the fracture toughness of the base metal. The failure pressure decreases with an increasing flaw size, at a given material fracture toughness value. The critical flaw size (at a given pressure or stress level) decreases as the fracture toughness is lower. In other words, the critical crack size decreases after switching from natural gas service to hydrogen or hydrogen blend service. Consider a pipeline pressurized at the MAOP, corresponding to a stress level of 72% SMYS. The critical size in natural gas is given by flaw #3, and the critical size in the hydrogen blend is given by flaw #4, with a size that is significantly smaller, Fig. 4. Finally, notice that this figure shows how failure by plastic collapse requires larger values of the fracture toughness when the crack size increases.

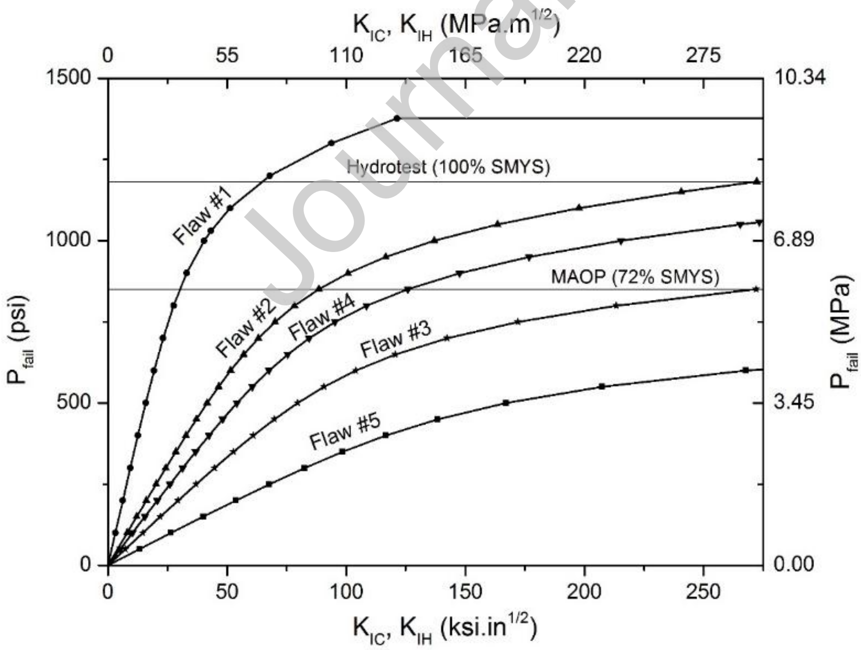

Fig. 3. Failure pressure of a pipeline with flaw #1 to #4 vs. fracture toughness, calculated according to FAD level 2 analysis [31], and using parameters shown in table 1.

Safety Margin After a Hydrotest

The third effect is related to the pipeline situation after a hydrostatic test [46]. Considering that the pipeline had been hydrotested at 100% SMYS, flaw #2 would have been the largest surface crack, with 2c/a=20, that could survive a hydrotest, Fig. 3. Any larger defect would cause a rupture, the pipe segment should be changed, and the pipeline retested until the hydrotest is successful. During a hydrostatic test, the fracture toughness of the material is controlled by K_{IC}. Hydrogen absorption in this environment should be negligible because the water used in hydrostatic tests usually has a low concentration of impurities and possibly inhibitors to minimize pipeline steel corrosion [25]. If the pipeline is put back in service in natural gas, fracture toughness of the material is still controlled by K_{IC}, and at the MAOP the flaw should grow considerably (for example up to the size of flaw #3) before it becomes critical. If the pipeline is put back in service in natural gas, the safety factor would be 1.39 for the case under study, table 2. If after a hydrotest the pipeline is put back in hydrogen blend service, the fracture toughness of the material would be controlled by K_{IH} = 127 ksi.in$^{1/2}$, because hydrogen can be absorbed in the gaseous mixture. Under this scenario, the safety factor would be 1.15. The flaw should grow to a considerable smaller size (for example up to the size of flaw #4) to become critical. In fact, if for some reason (for example a higher H_2 pressure in the blend, or the nucleation of the crack in a hard or susceptible microstructure) the K_{IH} decreases below 88 ksi.in$^{1/2}$, the flaw that was stable in the hydrotest at 100% SMYS would be unstable in the hydrogen service at 72% SMYS. It is concluded that hydrogen blending, hypothetically, can cause a special case of "pressure reversal". Pressure reversal refers to the occurrence of failure at a pressure level below the pressure level of the hydrotest [25].

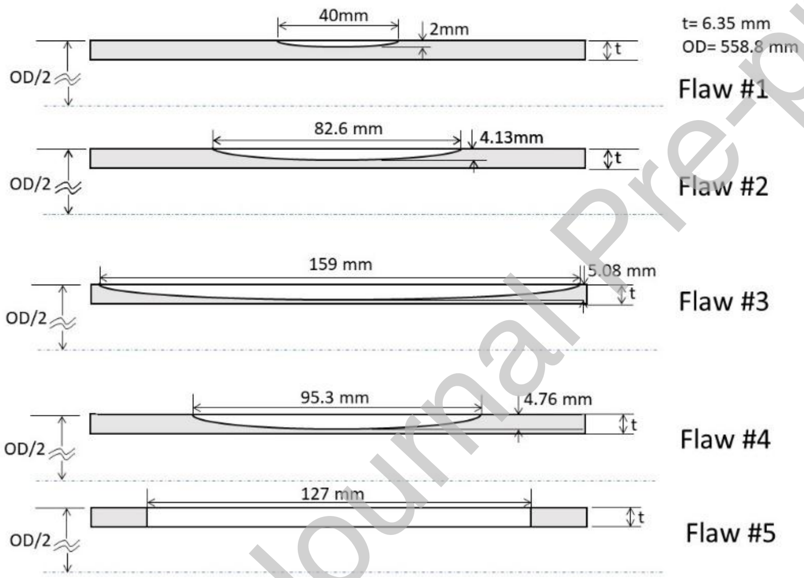

Fig. 4. Cross sections of external, semielliptical flaws analyzed in this paper. Figure drawn at scale. Flaw #1 has a 90% POD with current ILI-EMAT technology. Flaw #2 has the critical crack size at a hydrostatic test at 100% SMYS. Flaw #3 has a critical crack size in natural gas, flaw#4 has a critical crack size in hydrogen blend. Flaw #5 is a through crack, with the same aspect ratio as flaw#1.

The smaller critical crack size in hydrogen compared to the critical crack size in natural gas (Flaw #4 vs. Flaw #3 in Fig. 3 and Fig. 4) requires more frequent hydrotests or a decrease in the estimated pipeline life. Flaw #2 would be categorized as Crack severity 2 in ASME B31.8s [40], because its failure pressure was larger than 125% MAOP but the stress level less than 110% SMYS. In natural gas, a pipeline with this crack category has a remaining life that exceeds 5 years [40]. The remaining life should be lower if the pipeline is put in hydrogen service after the hydrotest, because the critical crack size is smaller in this case. Flaw #2 has a failure pressure of 6.76 MPa (980 psi) in the hydrogen blend (vs. 8.14 MPa or 1180 psi in natural gas), Fig. 3 and table 2. Extrapolating with the same criteria developed for natural gas to the hydrogen service, this crack would be categorized as Crack severity 3, because 125% MAOP>P_{fail}>110% MAOP, and its remaining life now would be 2 years.

The remaining life could be extended with a pipeline derating after switching to hydrogen blending service. The safety factor after a hydrotest for Flaw#2 was reduced by 17%, table 2. Consequently, if after a hydrotest it is desired to operate the pipeline with the same safety factor than in natural gas, the MAOP should also be derated by 17%. There will be an economic penalty to be considered because this will affect the energy transport capacity of the pipeline.

DISCUSSION

Hydrogen Affected Fracture Toughness, a Key Parameter for Pipeline Integrity

This paper highlights that the hydrogen affected fracture toughness is a key parameter required for the safe transport of hydrogen in pipelines. The materials properties used for failure assessment with the FAD are fracture toughness, S_Y and UTS. For pipeline steels, only fracture toughness decreases when tested in gaseous hydrogen [8, 21, 32]. When the fracture toughness is low, failure occurs by brittle fracture, if toughness is high, failure occurs by plastic collapse, figure 5. The extreme cases shown in figure 5 limit the maximum and minimum possible decreases in failure pressure, as a consequence of the decrease in fracture toughness by HE. For brittle fracture, failure pressure in hydrogen decreases in the same percentage as K_{IH} from K_{IC}. If the MAOP in both services is the same, then also the safety factor decreases in the same percentage as K_{IH} decreases from K_{IC} (f_{H2} = C´O´/D´O´ vs. $f_{natural\ gas}$ = CO/DO). For failure by plastic collapse, failure pressure in hydrogen service is the same than in natural gas. This would correspond to a K_{IH} higher than K_{IH}* in Fig. 2. The safety factor is the same in both services (A´O´/B´O´= AO/BO). In the present paper, Flaw#1 failed by plastic collapse, the rest of the flaws failed by elastoplastic collapse. Hence, the decrease in failure pressure and safety factors by hydrogen embrittlement were bound between 0 and 53% (in the hydrogen blend the fracture toughness decreased by 53% with respect to the air measured value, table 1). This maximum reduction in failure pressure and safety factors is confirmed considering previous literature results where the FAD approach was used to estimate HE effects on pipelines pressurized with pure hydrogen or blends [21, 30, 33].

For most existing natural gas pipelines, defects larger than Flaw#1 might be present, and K_{IH} will be an unknown parameter. Not even K_{IC} is required by current API 5L pipeline specification [43], so it is reasonable to assume that its value is unknown for most existing pipelines. It could be estimated from Charpy impact tests [31]. However, just in 2000 [47] a minimum level of absorbed energy in impact testing was made mandatory by API 5L Specification for PSL 2 pipes (product specification level 2) [43]. Measuring K_{IC} or Charpy values in existing pipelines involves removing samples and destructive tests. What is more, at present measurements of K_{IH} are expensive and performed by few laboratories in the world. For prioritizing measurements, calculations described in this paper can be first performed assuming K_{IH}=0.5 K_{IC} and using K_{IC} estimated from Charpy data if that is the only information available. Pluvinage et. al [21] compared K_{IH} and K_{IC} for several pipeline steels with grades ranging from API 5L X42 up to X70, and the average K_{IH} was 65 % of K_{IC} in H_2 at 6.9 MPa, similar to the conclusions of recent literature reviews [10, 11, 32]. Hence, using K_{IH}=0.5 K_{IC} is a simple and conservative criterion for an initial screening with those steels, which predominate in existing natural gas pipelines. Some K_{IH} tests can then be performed in prioritized segments, for example those with the smallest estimated failure pressure. It is important to include base metal, welds and heat affected zones in fracture toughness testing programs. It is warned that the K_{IH}=0.5 K_{IC} criterion could not be conservative for higher grades or heat affected zones of welds.

The fracture mechanics parameters used for the analysis presented in this work were obtained following ASTM E1820 standard [16], instead of the ASTM E1681 [27] standard currently recommended by ASME B31.12 [2]. ASTM E1820 involves tests with fatigue precracked specimens loaded at increasing load displacement in an autoclave pressurized with hydrogen. The onset of crack propagation is measured and converted to an equivalent K_{IH} value. In the most used alternative of ASTM E1681 [27] tests, a fatigue precracked specimen is first loaded at constant displacement with a bolt in an inert environment, and then exposed to hydrogen in a pressurized autoclave at the design pressure of the component. For materials with yield strength below 800 MPa (which is the case for steels used in most existing pipelines) more conservative results [48] are obtained when crack tip plastic straining and hydrogen absorption occur simultaneously

(ASTM E1820 tests) than in sequence (ASTM E1681 tests). Notice that in the actual application it is the pressurized hydrogen which is the cause of stresses in the material, so that environmental exposure occurs simultaneously with crack tip straining. For this reason, some authors [48] argue that constant displacement test violate assumptions of similitude and yield non-conservative results.

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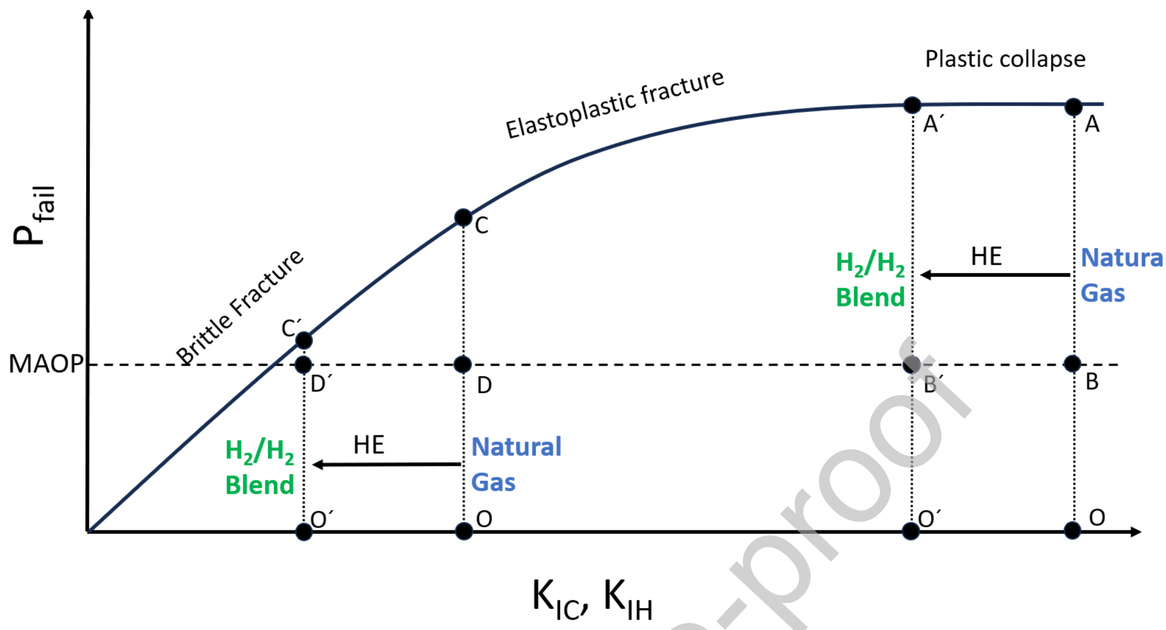

Fig. 5. Failure pressure vs. fracture toughness, for a pipeline with a given defect size, estimated with FAD approach. Hydrogen embrittlement (HE) causes a decrease in fracture toughness. The consequent decrease in failure pressure is maximum when failure occurs by brittle fracture, and null if fracture occurs by plastic collapse. Safety factors when the pipeline operates at MAOP can be calculated with the height of segments, for example for brittle fracture in H_2 service, f_{H2}=C´O´/D´O´.

Present Approach Limitations

The calculations performed in this work do not take any credit for the possible presence of gaseous inhibitors, like oxygen or carbon monoxide, which could be present in natural gas. Oxygen can inhibit the decrease in fracture toughness even when it is present at a 50-ppm concentration in the mix [4]. Furthermore, the oxides present in the internal pipe surface (mill scale, or formed during service or hydrotest) could hinder hydrogen absorption [49]. Nevertheless, the long-term barrier and inhibition efficiency of oxides and gas phase inhibitors, respectively, have not been established.

It is warned that actual values of failure pressure at a given crack size, or crack size at a given pressure, are a strong function of fracture toughness, Fig. 3. Fracture toughness varies with the material. The values used in this work were recently measured in a microalloyed API 5L X52 pipeline. "Vintage" or C-Mn steels have much lower values of K_{IC}. Reported K_{IC} (in air) values for vintage X46 and X52 base material are between 100 and 150 MPa.m$^{1/2}$ [50]. For the weld metal they were 40 MPa.m$^{1/2}$. Those values would further decrease in a hydrogen blend, promoting brittle failure [32].

Fracture toughness values used in this work were obtained from measurements of J integral [3, 51]. K values were obtained using the 0.2 mm-offset construction line in the J vs crack extension graph, as detailed in [16]. In tests where crack tip position was measured with the DCPD (direct current potential difference) technique [52], it was concluded that crack extension occurred before this conventional K was reached. In other words, critical values for crack initiation were much lower (1/3 or 1/2, according to [52]) than values obtained using the 0.2 mm-offset ASTM E1820 (2020) convention [16].

At present, it is unsolved if the same convention for obtaining critical values of K developed for air measurements, is applicable to hydrogen gas measurements. Using K values corresponding to the onset of crack initiation, as measured with the DCPD technique, would result in smaller values of failure pressure and critical crack size, Fig. 3. On the other hand, it is timely to remind that critical K values are used for level 2 assessments of crack stability [31]. Level 2 assessments are conservative because they do not consider the increased resistance to ductile tearing as the crack advances, typically observed in ductile materials like pipeline steels, even when tested in gaseous hydrogen [52].

Pipelines transporting natural gas typically operate at pressure close to MAOP, with fluctuations related to seasonal components, demand and episodic events related to service or upset conditions. In other words, there are multiple sources of cyclic loads so that the possibility of fatigue should be considered in a surpassing integrity analysis. Hydrogen gas increases the FCGR. To perform an integrity analysis including fatigue effects, loading frequency and load ratio R (K_{min}/ K_{max}, stress intensity factor ratio during fatigue) are required. Research is needed to understand the hydrogen effects in crack propagation under the so-called ripple load (R close to 1), which characterizes the situation of pressurized transmission pipelines operating at steady state [6].

Finally, loading history could affect crack tip stress state and hence the rate of crack propagation [53]. For example, a hydrotest causes plastic deformation at the tip of cracks. After unloading, the tip of the crack is under compressive residual stresses. Under cyclic loading, those compressive stresses retard crack extension, resulting in a beneficial effect that extends pipeline life [53]. At present, it is unknown if those compressive residual stresses could also affect the value of K_{IH}.

Future perspectives

The consequences described in this work should be considered in the standards needed to regulate hydrogen blending in pipelines. Currently, from a pipeline operator's point of view there is ambiguity regarding which standard applies to blending. The ASME B31.12 [2] code applies to service in 10% molar hydrogen or higher. The ASME B31.8 code [39], used for the construction of most existing natural gas linepipes, applies to gas defined as "any gas or mixture of gases suitable for domestic or industrial fuel and transmitted or distributed to the user through a piping system". There is not any restriction in hydrogen content, but certainly the code was not written considering the possibility of injecting hydrogen in pipelines.

Considering the calculations performed in this work, even when the hydrogen blending percentage is below 10%, there could be a significant decrease in failure pressure and critical flaw size with respect to natural gas. The suitability of a pipeline for transporting hydrogen should be evaluated in a case-by-case scenario, considering pipeline operating pressure and load, microstructure and grade of construction material, welding procedures and hydrogen affected mechanical properties.

CONCLUSIONS

Considering elastoplastic fracture mechanics, and recent results reported in the literature, this work shows that the decrease in fracture toughness by gaseous hydrogen has 3 important consequences on pipeline integrity:

- The failure pressure of the pipeline was reduced. The reduction occurred in a nonlinear fashion. If the predicted mode of failure is brittle fracture, then the FAD approach anticipated the largest decrease in failure pressure. In this case, after injecting hydrogen, the failure pressure decreased in the same fraction than the fracture toughness did by HE. For small defects, i.e., just below the detection limit of in-line inspection techniques, the predicted mode of failure was plastic collapse and the failure pressure in the blend was the same as in natural gas. For failure under elastoplastic fracture, the reduction in failure pressure will be bounded by the limits of the previous cases.
- If after blending hydrogen the pipeline is operated at the same MAOP than in natural gas, the safety factor can be reduced by up to the same fraction than K_{IH} is reduced from K_{IC}. The amount of reduction is dependent on predicted failure mode.

- The size of the critical flaw was smaller in a hydrogen blend vs. natural gas. This will represent an additional technological challenge for crack detection methods.
- After a hydrotest, a flaw that survived such test must grow a much smaller value to become critical in a hydrogen blend vs. natural gas. This effect should be counteracted with a decrease in operating pressure, or with an increase in the frequency of hydrotests or in-line inspections.
- It is possible that a crack that survived a hydrotest at 100% SMYS could become critical in hydrogen service at 72% SMYS.

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Declaration of interests

☒ The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

☐The authors declare the following financial interests/personal relationships which may be considered as potential competing interests:

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