ENERGY TRANSITION AND THE IMPACT ON PIPELINE INTEGRITY

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ABSTRACT

The climate emergency is one of the biggest challenges humanity must face in the 21st century. We all need to be involved in the process of moving towards a decarbonized economy. At the same time, the advancing global energy transition faces many challenges when it comes to ensuring a sustainable, reliable and affordable energy supply. The energy industry is currently going through its biggest change in living memory, despite this gas and its valuable infrastructure continue to play a major role in a decarbonized and integrated energy system. Scaling up the transportation of renewable and low-carbon gases in our global existing and new build pipeline network is essential to deliver a reliable and affordable transition to climate neutrality.

This paper will illustrate the important role of pipelines in an integrated future energy system, and explore the implications of pipeline transportation of renewable and low-carbon fuels and their associated products. In particular, the implications for pipeline integrity and inspection will be investigated.

INTRODUCTION

The climate emergency is tangible. Storms, wildfires, droughts and other extreme weather phenomena fueled by climate change have hit more than 4 billion people over the last two decades and the cost of these disasters in 2018 alone amounted to 160 billion US$. The future projections of damage caused by the emission of greenhouse gases are dire and incalculable. Rising global temperatures, shrinking glaciers, warmer oceans, vanishing coastlines and increasing natural catastrophes [1].

This climate crisis is one of the biggest challenges humanity must face in the 21st century. A worldwide and deep decarbonization of all sectors is urgently needed to mitigate global warming to well below 2 degrees. As announced in the European Green Deal, the European Union (EU) aims to fully decarbonize its economy by 2050, which requires a complete overhaul of the energy system and its valuable infrastructure [2].

Achieving the ambitious goals of EU climate policy will require significant investments in energy efficiency, renewables, new low-carbon technologies and grid infrastructure. It will also necessitate the close integration of the electricity and gas sectors and their respective infrastructures. A decarbonized Europe will be based on an interplay between renewable electricity and renewable and low-carbon gases in an integrated energy system to transport, store and supply all sectors with green energy to deliver a reliable and affordable transition to climate neutrality. A number of studies have shown that the existing gas infrastructure and knowledge can support the transition to net-zero in the most efficient manner. As the energy transition advances, the valuable pipeline system will provide efficient transportation and storage capacity for renewable energy in the form of molecular energy carriers, making the energy system more flexible and resilient [3].

Reaching the target of net-zero emissions by mid-century can only be achieved by a shared determination from all involved in the energy system based on an integrated architecture. This is only possible by significantly scaling up the production of renewable and low-carbon gases, and other synthetic fuels.. Hydrogen is at the core of these integrated future energy systems. It will mainly be produced via electrolysis of water with electrical energy from renewable sources ('green H_2') or from steam methane reforming with corresponding carbon capture, utilization and storage (CCUS) ('blue H_2'). Hydrogen will realize long-term, seasonal energy storage on a large scale and can be used as a direct fuel or as a feedstock for various industries. In order to decarbonize hard to abate sectors, it can also be converted via synthesis with carbon

dioxide into synthetic e-fuels such as biomethane, biomethanol or other carbon-based chemicals. Ammonia from green hydrogen and nitrogen is another promising application for various industries [1].

Low-carbon gases, biogases and Renewable Natural Gases (RNG) and their associated products can reliably and efficiently be transported, stored and distributed in our global existing and new build pipeline network. Pipelines will also be used in assisting carbon capture, utilization and storage (CCUS) projects by transporting carbon dioxide safely from emission locations to permanent storage or end use locations. For this reason, pipelines continue to be important and will play a critical role in an integrated future energy system.

The transportation of these fuels through pipelines will require general as well as specific integrity threats and damage mechanisms are considered to ensure a safe and efficient operation. These challenges can only be managed with a comprehensive integrity management system. Only then can effective inline inspection technologies be specified to target the specific threats and damage mechanisms accurately. The following chapters investigate the implications of future fuels and their associated products on the integrity of pipelines and inline inspection solutions.

This paper will not address ammonia and biomethanol liquid pipeline challenges in detail, apart from noting that both ammonia and bio-alcohols have their own particular characteristics and associated integrity threats e.g. internal stress-corrosion cracking (SCC).

INTEGRITY THREATS

If future fuels (or indeed any fuels) are to be transported through pipelines, pipeline integrity must be assured to allow for long-term safe operation. This concept of integrity management is not new to pipeline operators, as demonstrated by the long, proud and overwhelmingly safe history of the existing pipeline network, but it is worth revisiting in the context of future fuels. In essence the key points of interest for any pipeline integrity management system are:

- Pipeline condition - *What are the time-dependent threats? Which type of defects should I tackle? Where? How severe?*
- Integrity Remaining Life- *How safe is my pipeline operations? How long?*
- Consequences- *What are the consequences of loss of containment?*
- Management - *Can I safely manage pipeline operations?*

The introduction of different fluids into pipelines will not change how Integrity Management (IM) shall be tackled, but it will introduce its own specificities and challenges. It is therefore necessary to consider each fluid in turn, identify the relevant threats and outline how these threats can be monitored, inspected and managed. The management of these threats is best understood in the context of an integrity framework, and example of which is shown in Figure 1, the concept of which is further outlined in [4].

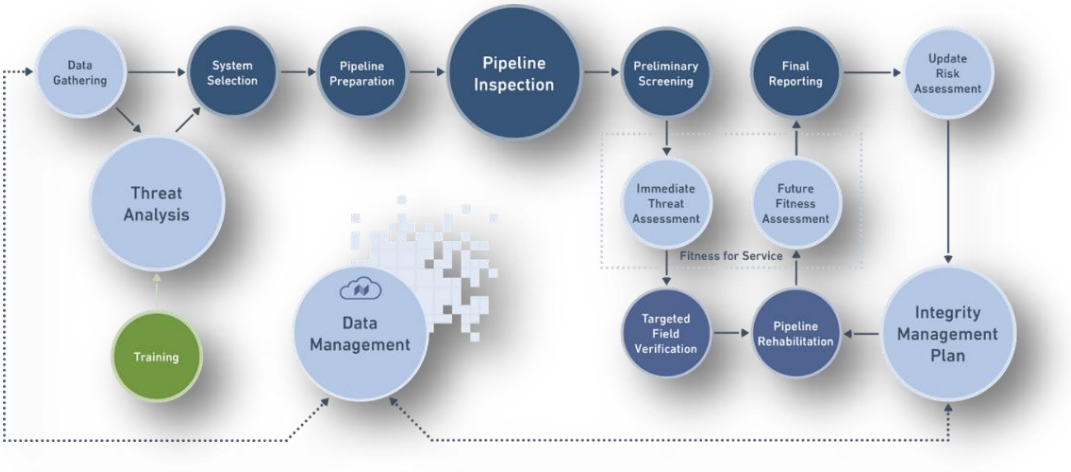

Figure 1 - Example of a Hydrogen Integrity Management Framework

General Threats (non-specific to service)

For any pipeline, the likelihood of internal-time dependent threats are generally directly related to, and result from, the fluid being transported. However, certain threats and defects could arise irrespective of the nature of the transported fluid.

The transported fluid will have only a peripheral impact on the occurrence of external threats, particularly in the case of external corrosion, 3rd-party damages, and geohazards. This also (generally[1]) applies to the occurrence of external Environmentally-Assisted Cracking (EAC) (i.e. external Stress-Corrosion-Cracking, Hydrogen-Induced Stress Cracking (Cathodic Protection-related)). Equally, certain flaws could be directly introduced during manufacturing and construction regardless of the intended service; and can pose an integrity threat on their own right.

It is thus important to recognise that the prevalence of some issues will not be influenced by the fluid being transported. In this context, such threats have been a key facet of existing pipeline integrity management programs. Almost half of European transmission gas pipelines are already >40 years old (Figure 2), and age (and the occurrence of external threats) is likely to have taken a toll on the current condition of these assets. As existing hydrocarbon pipelines are targeted to be repurposed for the transportation of future fuels, the diagnostics of the pipeline condition against external corrosion, 3rd-party damages, geohazards and cracking will become even more important for safe conversion and onward.

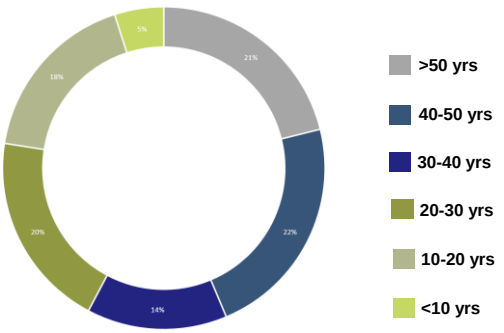

Figure 2 - Age of Natural Gas Transmission Lines in Europe (2021) [5]

[1] In the case of Hydrogen service, H_2 may compound the likelihood of external SCC (particularly that of Near-Neutral pH SCC) and HISC. However, the influences need to be further quantified. [10]

Table 1 shows the inspection technologies that should be necessary through the conversion process and future operations, in order to address the management of these 'General' integrity threats, regardless of service and future fuel transportation.

Table 1 – Main ILI technologies for the management of 'General' Integrity threats (irrespective of service)

Threat	Feature type	ILI technology examples
External corrosion	Metal loss	RoCorr MFL-A, RoCorr UTWM
Third-Party Damages	Dents, gouges	RoGeo-XT
GeoHazard	Bending strain	RoGeo-XYZ
Manufacturing / Construction (materials & welding)	Crack like / cracks	RoCD EMAT-C, UT-C
External EAC (ext. SCC / HISC)	Cracks	

In addition to these 'general' threats, it is known that methane is essentially inert with respect to pipeline carbon steels. In contrast, gases such as hydrogen or CO_2 can interact with the pipeline either by means of hydrogen embrittlement or corrosion (in the presence of water). It is therefore a truism to say that changing the service of a pipeline from natural gas to a future fuel will never make anything better from an integrity point of view, and may well make things more challenging. The natures of these challenges, and approaches to manage them, are explored further below.

Hydrogen

As has been noted many times, hydrogen pipelines are not new technology and gaseous hydrogen has been successfully manufactured, transported and stored in carbon steel infrastructure for hundreds of years [4], [6].

Table 2 - Existing Hydrogen Pipelines by Region

Region	km	miles
U.S.	2608	1621
Europe	1598	993
Rest of World	337	209
World total	**4542**	**2823**

Despite this, there are important differences between hydrogen and natural gas pipelines. These differences principally arise due to dissociation of the gaseous molecular hydrogen at the internal pipe wall via Sieverts' Law [7] and consequent absorption of atomic (or ionic) hydrogen into the metallic pipe wall lattice. The implications of this absorption, and the quantitative effect of the consequent hydrogen embrittlement on pipeline material properties and integrity, are the subject of much recent interest and research [8]. In summary the major effects of hydrogen on material properties are to reduce ductility, reduce fracture toughness and increase fatigue crack growth rate in hydrogen compared to air. The magnitude of these effects varies widely in the literature but there appears to be a clear agreement that there is a strong microstructural dependency [9].

To help quantify the effects of gaseous hydrogen, ROSEN have developed a dedicated gaseous hydrogen test laboratory which will be operational in 2022.

Existing hydrogen pipeline design codes, notably ASME B31.12 [10] and the EIGA guidelines [11], are significantly more restrictive than their natural gas equivalents [12] in two major respects. Firstly, hydrogen codes tend to require lower allowable utilisation factors (the hoop stress as a proportion of SMYS) and secondly hydrogen codes are significantly more restrictive in terms of material properties, strongly encouraging the use of lower grade (=<X52 / L360) steels and requiring more extensive testing and more restrictive chemical compositions. The cumulative effect of these restrictions is that existing hydrogen

pipelines generally operate at lower pressures than their natural gas equivalents. If existing natural gas pipelines are to be repurposed to hydrogen then it will be necessary to (at least) maintain their existing operating pressures to maintain energy throughput. This in turn means that hydrogen specific threats (principally cracking) need to be understood, which in turn means that a robust understanding of both existing crack-like defects and material properties in the pipeline is required; the crack management of hydrogen pipelines is discussed in [13]. Equally, if the aim is to limit the hoop stress in order to comply with existing codes then a robust knowledge of wall thickness and any localised thinning or metal loss is needed. Indeed ASME B31.12 (Clause PL3.21 (o)) states that "If there is reason to believe that there has been a reduction in wall thickness since original construction, measurement of wall thickness along the length of the pipeline shall be done using a suitable internal inspection device".

Table 3 shows the inspection technologies that should be necessary through the conversion process and future operations, specific to hydrogen service. This is further discussed in detail in [6] [13].

Table 3 – ILI technologies specific to the management of Integrity threats in hydrogen service

Threat	Feature type	ILI technology examples
Material Embrittlement	Low fracture toughness under H_2 [Note 1]	RoMat PGS [Note 1]
Hydrogen - Cracking damages [Note 2]	Cracks	RoCD EMAT-C
Additional considerations	Hard spots [Note 3]	RoMat DMG
	Geom. Anomalies [Note 3]	RoGeo-XT
	Bending strain [Note 3]	RoGeo-XYZ

Note 1: Defining material population profiles will be key to proceed to sampling and fracture toughness testing under ***H_2*** **[6] [13]**
Note 2: Refer to **[13]**
Note 3: These features will increase susceptibility to embrittlement and cracking in H_2

Carbon Dioxide

The sequestration of carbon dioxide, whether as part of "blue hydrogen" production or as part of another form of CCUS project, is likely to be integral, at least in the short term, to any future decarbonised energy supply. This sequestration will require pipelines, and for economic reasons it would be very advantageous if the carbon dioxide could be transported in its dense phase rather than as a gas.

Similarly to hydrogen, the storage and transport of carbon dioxide in carbon steel pipelines is not a new technology, and the concept of CCUS (and the consequent requirements for carbon steel pipelines) was the subject of intense interest in the early 2010's [14] [15],. It is fair to say that the roll-out of CCUS technologies has not been as rapid or complete as some of the more optimistic predictions from the 2010's, however the underlying rationale remains and interest in CO_2 pipelines is currently undergoing a renaissance, with the current understanding of pipeline integrity threats being summarised in [16].

In essence the principal time dependent threats specific to CO_2 pipelines are internal corrosion (if water is present) and potential stress corrosion cracking (SCC) (if water and either CO or H_2S are present in addition to CO_2)[2]. This dependence on the presence of free water means that these risks can be controlled operationally, and indeed this has been done successfully in existing CO_2 pipelines. It should however be emphasised that the existing total length of CO_2 pipelines is less than 10,000 km as shown in Figure 3, cumulative operational experience of CO_2 pipelines is therefore significantly less than for their hydrocarbon equivalents and the pipeline industry has a long and painful history of operational upsets.

[2] There is some evidence to show that SCC can occur in just CO_2 and water, however this has only been recorded on high strength steels under high-pressure CO_2 environments, extreme plastic stresses and long exposure times [19]

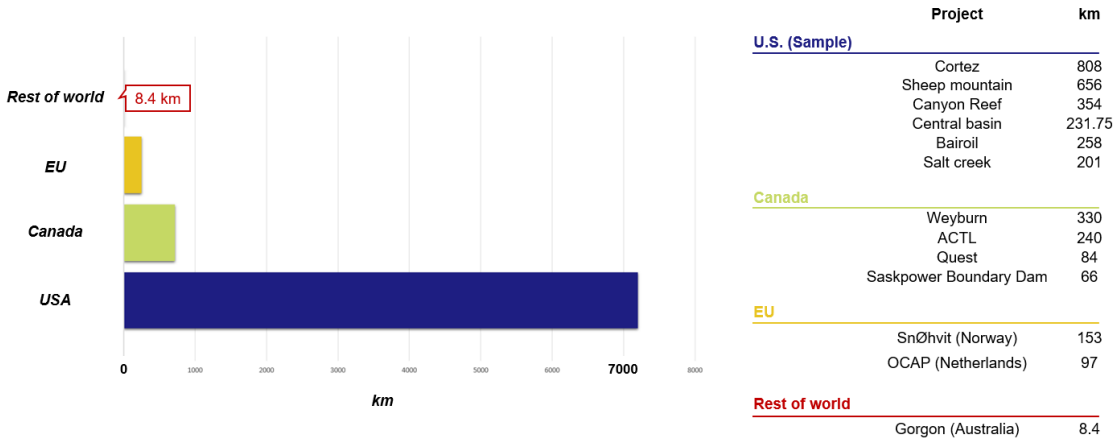

Figure 3 - Existing CO_2 Pipelines [16]

Although not strictly speaking an integrity threat, the other aspect of CO_2 pipelines that has been the subject of intense interest is fracture control, in particular long-running ductile fracture in dense phase pipelines [16]. Ductile Fracture control in hydrocarbon pipelines is traditionally managed using the semi-empirical Battelle Two Curve Model (TCM) [17]. In essence this model states that, for a given internal pressure, a ductile fracture will only propagate if the gas decompression speed (driving force) is equal to or lower than the fracture propagation speed, see Figure 4.

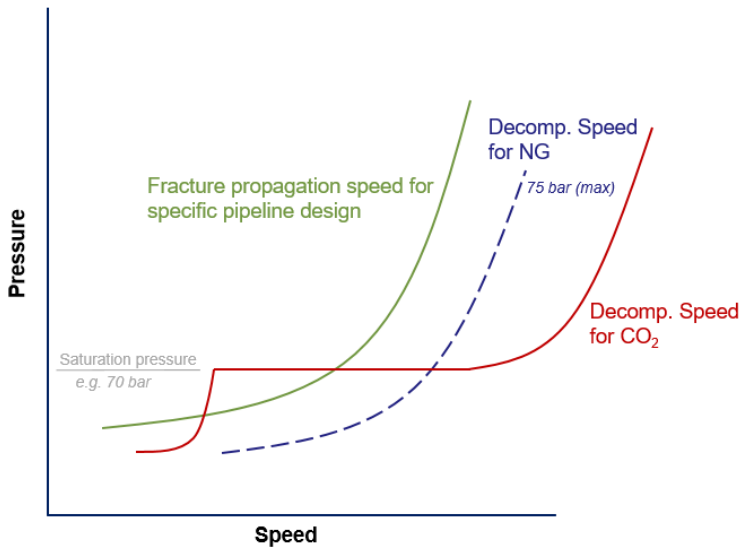

Figure 4 - TCM schematic showing decompression speed for CO_2 and NG relative to fracture propagation [18]

As shown above, dense phase CO_2 exhibits a long "plateau", or saturation pressure, at the boundary between liquid and gas phases. The interpretation and implication of this plateau is discussed in various papers, notably [19], [20] and [21]. However the current consensus is that to avoid running ductile fracture the pipeline material toughness should be such that the arrest pressure (which is a function of material properties (fracture toughness) and pipe dimensions), should be (conservatively) above or equal to the saturation pressure (associated with the plateau). Some practical guidance about how to implement this for existing pipelines is given in [18], although application of this guidance can be challenging due to the prerequisite pipeline characteristics[3]. Regardless, if existing pipelines are to be converted then an in-depth understanding of material properties is required.

[3] Applicability for grades (only X60 or X65), pipeline dimensions (16 - 36" OD, 10 - 26 mm WT) and pipe type (only Submerged Arc Welded [SAW] Thermo-Mechanically Controlled Process TMCP pipes).

Table 4 shows the inspection technologies that should be necessary through the conversion process and future operations, specific to CO_2 service. This is further discussed in detail in [16].

Table 4 –ILI technologies specific to the management of Integrity threats in CO_2 service

Threat	Feature type	ILI technology examples
Ductile Fracture	Low Material toughness	RoMat-PGS [Note 1]
Internal corrosion	Metal losses	RoCorr MFL-A
Internal SCC	Cracks	RoCD EMAT-C
	Hard spots [Note 2]	RoMat-DMG
	Geom. Anomalies [Note 2]	RoGeo-XT
	Bending strain [Note 2]	RoGeo-XYZ

Note 1: Defining material population profiles will be key to proceed to sampling and fracture toughness testing **[16]**
Note 2: These features will increase susceptibility to SCC

Biogas

Biogas and renewable natural gas (RNG) are closely related, and there are as yet no standardised definitions of the nomenclature. For the purposes of this paper biogas is defined as the gas which is anaerobically generated from waste (for example at landfill sites, or through anaerobic digestion (AD) at dedicated facilities). Raw biogas typically contains 45-65% methane, the exact composition depends on the source of the biogas but typical impurities include water and CO_2 together with lower or trace levels of siloxanes, volatile organic compounds (VOCs), H_2S and potentially nitrogen and oxygen. This raw biogas requires treatment, or upgrading, to remove the impurities. Once purified, biogas becomes RNG, which typically has a methane content of 96-98 % [22]. In this context, it becomes clear that from an integrity point of view RNG has very similar properties to conventional natural gas and, if the purification process and compositional limits are controlled, can be treated in a very similar way in terms of integrity management. Conversely, raw biogas has different properties, and therefore a different integrity profile. This differential is recognised in for example the IGEM suite of standards, where raw biogas pipelines are referenced in TD/17 [23] while once injected into the network, RNG is treated in the same way as conventional natural gas.

Biogas and RNG are already well established as energy sources, with the number of biogas projects predicted to expand significantly over the coming few years. Within the US alone, the number of planned or under construction projects already exceeds the number currently operational (Figure 5).

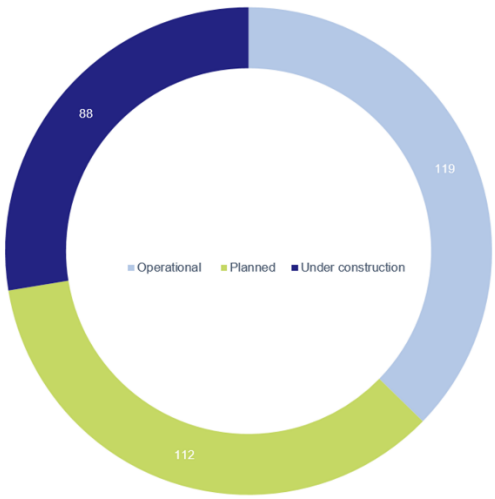

Figure 5 - Number of US Biogas Projects (2020) [24]

Currently most biogas projects operate on the principle that the biogas upgrading plant (BUP) should be as close as possible to the AD facility, minimising the length of pipeline required to transport raw biogas. After the BUP there is often a connector pipeline to link the (upgraded) RNG into an existing natural gas network. It is however possible that this model may change, with it potentially being more economic to have a centralised large scale BUP fed by a large number of disparately spaced AD facilities, with a concomitant requirement for more biogas pipelines.

From the integrity management point of view, biogas is intrinsically different from, and poses different threats to, RNG. AD facilities will typically generate biogas at low pressures, however the composition means that internal corrosion and cracking threats need to be considered. IGEM TD/17 references these threats, and recommends the use of stainless steel or PE pipe rather than carbon steel. In this context it is important to realise that, while the use of appropriate materials can mitigate against time dependent threats, no material is immune to degradation. Stainless steel and PE pipes can and do fail if the environmental conditions or stress (or commonly both) are sufficiently severe. RNG connector pipelines are normally designed and constructed in accordance with conventional natural gas pipeline codes, however the integrity management of these pipelines should take into account the potentially different impurities and the potential for operational upsets in the BUP.

The inspection technologies required for biogas and RNG will depend on the exact threats of concern. For RNG they will typically be the same technologies required for other natural gas lines, although the relative requirements may differ depending on composition. An additional challenge is that biogas collector pipelines are frequently unpiggable, meaning that innovative solutions may be required.

INSPECTION TOOL REQUIREMENTS

Knowing the integrity threats for pipelines related to hydrogen or other future fuels we can acknowledge that different kind of In-line Inspection (ILI) technologies can support the integrity management of such pipelines. Those ILI technologies could be technologies for detection of e.g. deformations, mapping or corrosion. Technologies could also include those particularly applicable to future fuels, for example determination of material properties or detection of cracks and crack-like anomalies in gas pipelines. In the following chapter, we will discuss challenges for inspections in the before mentioned products and how inspections can be realized.

ILI tool components

ILI tools and cleaning tools are prepared for each survey according to the pipeline requirements. Such preparations consider mechanical and operational conditions. Information that is considered include e.g. pipeline length, flow rates, product temperature and pressure, survey duration, minimum ID, minimum bend radius and many more. A main challenge for ILI in future fuels are the properties of such fuels and the impact on ILI tool materials, and the different operational conditions when running in hydrogen for example.

Conventional ILI tool designs and configurations are optimized for application in hydrocarbons at moderate pressure (≤ 150 bar) and temperatures (≤ 80 °C) and limited exposure time. Typical hydrocarbons are crude oil, refined products (e.g. Diesel or Jet Fuel) and natural gas or LPG, containing low concentrations (≤ 5%) of other chemicals. Different pipeline products could severely affect the integrity of some tool parts, significantly increase the risk of a tool malfunction, and reduce the tool run time and service life.

Commonly used types of material are described in the following figure.

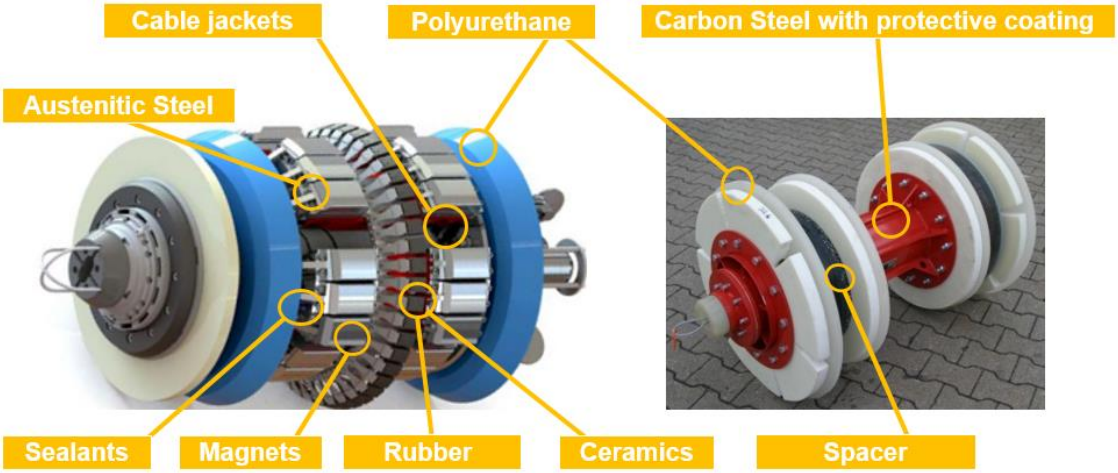

Figure 6 - ROSEN Tool design - commonly used types of material

Elastomer parts, like polyurethane (PU) discs and cups, cable jackets and O-rings are usually more affected by pipeline fluids than metal parts. Decompression of elastomer parts is one challenge that is typically avoided by careful management at the pipeline receiver site. This decompression fortunately does not affect the data quality, since the effect occurs during and after retrieval procedure, and not during the inspection itself. The replacement of the exposed parts is therefore required after inspection in critical fluids and in preparation of the tool for the next inspection.

A similar or even stronger effect than described above is also valid for products that are in a supercritical state. As an example, CO_2 becomes supercritical above its critical temperature of 31.0 °C and a critical pressure of 73.8 bar. Above these conditions, there is no frontier between liquid and gas, and small changes in the temperature or pressure could result in continuous changes in the product's density, solvent power and other physical properties [25]. Its low viscosity combined with high diffusivity and high density leads to higher permeability through elastomers and high intrusion rates at interfaces (e.g. cables, connectors, sensors). Elastomers tend to absorb supercritical fluid during exposure and lead to an increased risk of blistering and cracking caused by explosive decompression.

Another important aspect for the preparation of any ILI in future fuels are the high flow rates and expected survey conditions due to the fluid's density.

For some technologies, the preferred tool run velocity is lower than for other technologies. In general the more stable and smooth the tool velocity is, the better the captured data quality. To allow the pipeline operator to continue operations with high flow rates during inspection, the utilization of permanent bypass or of smart speed control units (SCU) in e.g. MFL and EMAT ILI tools have proven in gas pipelines.

Depending on the ILI tool size, configuration and the flow and pressure condition in the pipeline an ILI tool velocity reduction between 1.5 m/s and ~6.0 m/s can be achieved by the utilization of a SCU compared to the flow rate of the natural gas. The lower density of H_2 or CO_2 might even be advantageous to create a certain velocity reduction of the ILI via SCU or permanent bypass. The capabilities of the SCUs in future fuels are under review at the moment and results will be shared in future publications.

Another important aspect, which needs further review, is the ILI tool motion in future fuels. As example the low density of hydrogen will result in less controlled survey conditions compared to methane. Because of the low density of hydrogen compared to methane the compression rate of hydrogen is higher, which will result in also higher expansion of hydrogen. Thus, we expect higher speed excursions in hydrogen than in methane due to the lower dampening effect of hydrogen. The following options can reduce the impact of the lower density of hydrogen:

- Increase of the minimum operating pressures
- Reduction of ILI tool differential pressure
- Permanent bypass
- Speed Control Units with controlled bypass

The utilization of speed control units and permanent bypass must be assessed carefully. The controlled bypass does support to reduce the tool run velocity at high product flow rates and to reduce velocity excursions while assuring that the ILI tool does not become stationary due to missing sealing. **[26]**. The control of a batch operation (necessary for UT inspection in a gas line), which implies control of both sealing and inspection pigs, can therefore be very challenging if not impossible.

Carbon Dioxide

As noted above, for economic reasons CO_2 pipelines are mainly designed to operate in the dense phase. The particular properties of dense phase CO_2 lead to additional challenges for ILI, mainly for the elastomer parts of the ILI tools. Fortunately ILI in CO_2 is not a very new challenge and experience has been gathered in the last ten to 20 years. Indeed ROSEN has inspected more than 30 CO_2 pipelines with a cumulative length of over 2.800 km, thus solutions are available to overcome the challenges.

CO_2 Case Study

A 24 inch diameter and 116 km long dense phase CO_2 pipeline was inspected with a geometry and Magnetic Flux Leakage (MFL) tool in two separate runs. The pipeline was operated at 131 bar, with a launching temperature of 16° C and a very low flow rate. The inspection duration was about 180 hours. After the runs the tool conditions were assessed. The wear of the cups and discs was in a normal range and were not significantly affected after the relatively long run and long exposure time. A few hours after tool receipt plastic and rubber parts started to swell and bubbles appeared. This was a first indication of the decompression effect and of the performance of different materials.

For both runs the data was recorded and collected successfully. Hence, both runs have been successfully accomplished.

Hydrogen

Apart from the effects that hydrogen can have on pipeline materials, it can also affect the materials within ILI tools, in particular magnets. To quantify these effects, ROSEN has conducted Hydrogen exposure tests at 100 bar, in 100% Hydrogen. The tests have verified that ROSEN tool components are resistant to Hydrogen. No visual defects were noted after the exposure test including a high decompression rate of 20 bar per minute. The functionality of sensors, cables and connectors remained unaffected. Polyurethane samples showed no loss of material properties. O-rings showed no significant changes in dimension and mechanical strength. Applied protective coating on magnets have proven successful and the magnets' properties were not affected. With the opening of ROSEN's dedicated hydrogen test facility, if new materials or components are developed, or further testing is required, this can be supported in-house.

Apart from the physical effects of hydrogen on the tool components, the flow characteristics of a hydrogen pipeline will differ from those of a natural gas pipeline.

Hydrogen Case Study

In 1996 a new 10 inch diameter and 19 km long pipeline segment was installed for the transportation of hydrogen. In 2015 the pipeline operator approached ROSEN for a method to safely inspect the line segment using hydrogen as the propellant with a combination of geometry and magnetic flux leakage technologies. Due to the harsh product, the tool was set up with non-standard cups, differing in Shore hardness. For the standard tool set up, a minimum pressure of 30 bar is typically requested. However, the operator was only able to provide a pressure of ~20 bar and a flow rate of 11 MMscfd. In order to reduce excessive velocity peaks from pressure build-up in installations while still providing enough seal to propel the tool through the line, various bypass holes and notches were applied. Finally, protective measures for the magnet circuits were taken. After the run, when the tool was received, there was no damage, and the cups showed minimal wear. The resulting data showed 100% sensor coverage for both the geometry and MFL portions, and magnetization levels were within the predicted ranges. While the tool did experience a few spikes in velocity, the data quality was acceptable for evaluation.

The operator returned to ROSEN when it was time to re-inspect the line segment. This time the operator was able to provide a pressure of ~24 bar while maintaining the same flow rate. Once again, the cups showed minimal wear, and the tool was in good condition after the run. During the data review, it was noted that the tool still experienced a few velocity spikes, but the increased pressure allowed for an overall reduced speed resulting in more stable inspection conditions. The data was again at 100% sensor coverage for both the geometry and MFL portions and the data was collected and recorded successfully.

Figure 7 - ROSEN MFL-A tool

Conclusions

The climate emergency and need for decarbonisation are real. If international targets are to be met significant investments in energy efficiency, renewables, new low-carbon technologies and grid infrastructure are required. In particular, the existing pipeline infrastructure has a key role to play in enabling this energy transition. In practice this means that ageing pipelines must be converted to transport fluids very different from those they were originally designed for. A comprehensive integrity-led approach is required to maintain safety during this transition. As developed by ROSEN, this integrity framework involves a detailed understanding of the different threats inherent in different gases together with the use of appropriate inspection tools to quantify these threats. Existing knowledge and experience in low carbon gases can be applied to enable the energy transition. Specific questions still remain with respect to quantifying the effects of gaseous hydrogen on specific material properties, but there are being addressed through testing programmes in dedicated hydrogen laboratories, including ROSEN's newly developed test facility.

In terms of ILI specifically, the service life and compatibility of the ILI tool parts strongly depend on the tool run conditions, the chemical composition of the fluid and the exposure time. Tool setups are optimized for typical conditions in oil and gas pipelines. Tests have been conducted with different fluids under the umbrella of future fuels. Available solutions are suitable to enable ILI in H_2, CO_2, ammonia and other future fuels.

Finally, the proposed inspection technologies for pipelines transporting future fuels will need to be assessed for each pipeline within the context of an integrity framework, however it appears likely that high resolution corrosion services, crack detection services and material properties services will be required. ILI vendors will need to provide these services in the environment of future fuels.

The energy transition requires a combined approach by the entire industry if it is to be safely managed. ROSEN believe that the use of an integrity framework approach combined with appropriate inspection technologies is the best way for the industry to address these challenges.

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