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Construction & Coating

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The Future in Pipeline Industry

Welcome to this latest edition of the Pipeline Technology Journal addressing a variety of contemporaneous pipeline topics including improvement in productivity and safety, repurposing old pipelines, advancement in repair techniques and inspections, coating integrity and achievements in under water installation.

Zahi Ghantous
Vice President - Construction Support & Quality Management- Consolidated Contractors Group S.A.L.

I am honored to have this opportunity to address the readers of this edition and share my insights on our pipeline industry and the trends affecting its future.

Unlike other industry segments, pipelines are unique in terms of being invisible structures when completed; they are normally constructed underground in highly challenging terrains and environments with a stretched-out operation area that entails the active engagement of multiple stakeholders and groups. These facts necessitated the need to adopt distinctive construction and inspection techniques that would ensure an efficient and streamlined workflow while also guaranteeing the integrity and longevity of the asset. Unfortunately, this also dictated that the adoption of changes that challenged established methods was an arduously slow process that required extensive examination prior to effectively being incorporated into the field.

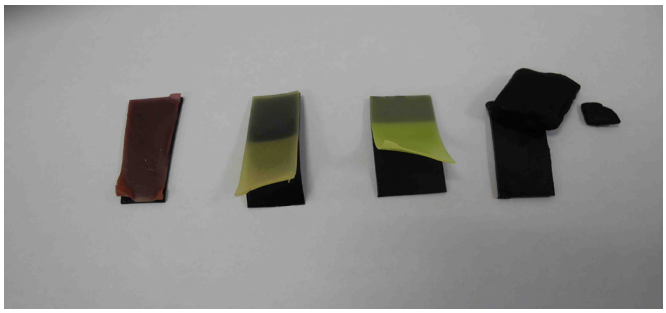
The construction industry, in general, still lags other industries in terms of the application of technologies and innovations. However, and with more developing technologies in recent years, the industry –especially Pipelines projects – increasingly started adopting more and more innovations and advanced methodologies capitalizing on the extensive R&D efforts now invested and the industry's general shift towards digitalization. This has enabled the achievement of better results and records ranging from the use of alternative pipe material, welding techniques, modes of inspections, integrity checks and the like. What was not achievable or doable a few years back is now happening and being successfully incorporated in the standard safe building process.

With the current movement towards carbon capture and green energy gaining more momentum, existing pipeline networks are now being repurposed to transport non-conventional media such as CO_2 and hydrogen. The ability to safely re-use existing pipeline networks will be a game changer soon. This further requires the industry readiness to actively engage in adapting modernized techniques and deploying them effectively into their operations. With further progress in Artificial Intelligence, Digital Technologies, and boundary-crossing collaborations, this course is set. It seems inevitable for future successful players in the industry to be on board the earliest possible.

Yours sincerely,
Zahi Ghantous, Vice President - Construction Support & Quality Management
Consolidated Contractors Group S.A.L.

This Issue's

COMPLETE CONTENT



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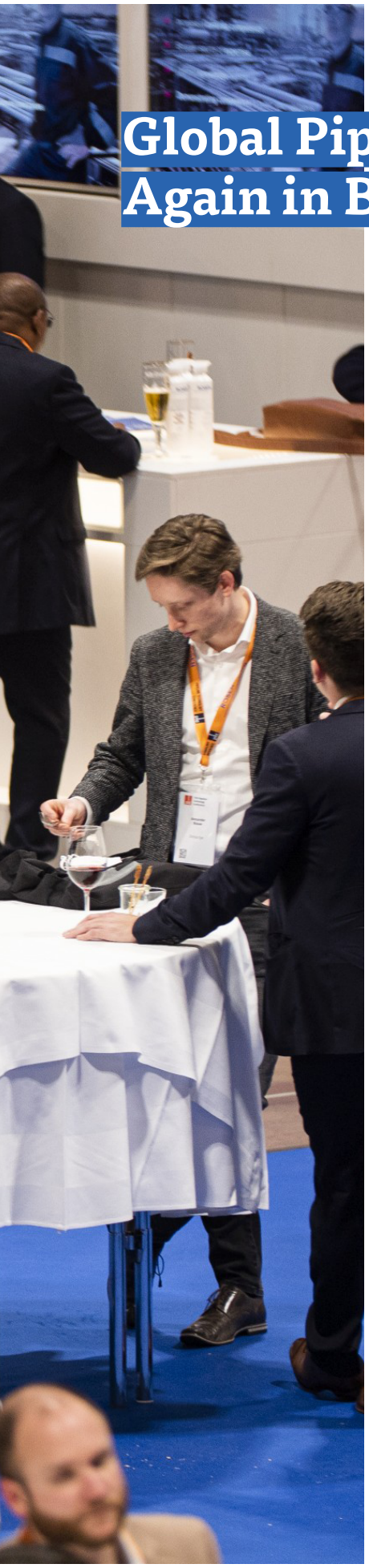


Global Pipeline Community to Meet Again in Berlin in May 2023

After two years of online Pipeline Technology Conference (ptc) and a hybrid event, ptc 2023 will once again focus entirely on face-to-face networking. From 8-11 May 2023, participants from all over the world will again travel to Berlin for the Pipeline Technology Conference and exhibition. About two-thirds of ptc visitors come from abroad. Delegations from 70 different pipeline operators were registered for the last ptc.

In addition to the traditional topics of safety, inspection, leak detection, construction and maintenance, next year's focus will again be on hydrogen, CO2 transport and methane emissions. Against the backdrop of the current geopolitical situation, political discussions and in-depth exchanges with operators from Europe, Asia and Africa will be addressed in the keynote lectures and discussion panels.

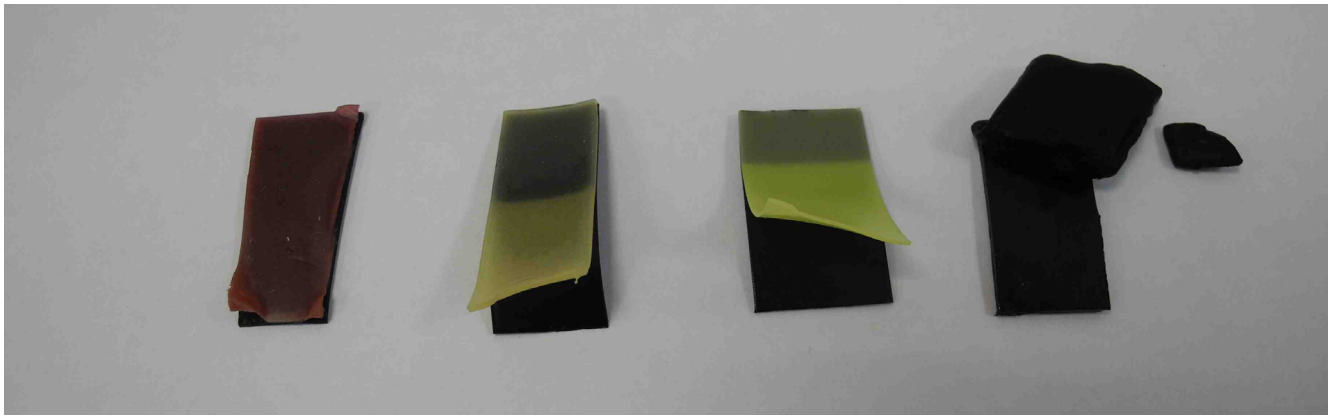
Besides the current topics and news on development and application in the conference, the exhibition is gaining more and more importance. Next year, the entire Hall 2 with 4,600 sqm will be occupied for the first time. Additional alternative space in the transition area between conference and exhibition will be used for special events. Already about 30% of the space has been sold.

A special focus will again be devoted to the area of promoting young talent. Apart from the active participation of pipeline students in the execution of the event, there will again be a joint booth of the international Young Pipeline Professional organizations and, for the first time, a separate award ceremony for students and young professionals.

With an extensive evening program and various networking events, next year's ptc will again offer a wide range of opportunities to exchange ideas with old acquaintances and new contacts from the global ptc community.

The call for papers for the conference is open until 30 September 2022.

More news from the ptj newsletter: www.pipeline-journal.net/news



Alkali resistance of coatings? Will tests of cathodic disbondment provide reliable statements to this question?

T. LÖFFLER > DENSO

Abstract

It is generally accepted that the effect of cathodic protection is based on the activation polarization and the concentration polarization of the steel surface resulting in an increase of the pH at the interface between steel and soil. This increase in pH value may affect the adhesion of the corrosion prevention coating in the immediate vicinity of the defect. The criterion of cathodic disbondment CD is therefore part of all serious standards for the corrosion protection material of steel pipelines laid in soil and water in conjunction with CP.

Interestingly, the effects of the alkaline environment on corrosion protection materials themselves have not yet been the subject of normative considerations, although possible damage to the coating material by alkali may pose a significant risk to the pipeline.

To close this knowledge gap, experts from various areas of the pipeline industry have developed a quick and easy to perform test.

The first results of this study will be presented in this paper. The results confirm a very different behaviour of the investigated materials, which properties can also differ significantly from the behaviour shown in the established CD test.

1. Introduction

A functioning and coordinated active and passive corrosion protection are decisive for the lasting integrity and failure-free functionality of a newly installed steel pipeline as well as for the achievement of its intended and planned service life.

Passive corrosion protection includes all measures which achieve a shielding/protective effect against corrosive media. This can be attained e.g. by an appropriate selection of anti-corrosion coating as well as design features. The function of a coating is to separate the metal surface to be protected from the surrounding corrosive medium (electrolyte) with respect of mass as well as charge transfer. Such the formation of corrosion cells is inhibited. The requirements for a coating are shown in figure 1.

Cathodic Protection CP (see figure 2) will act as a second line of defence in the event a defect occurs in the corrosion prevention coating.

For technical and economic reasons pipelines are usually protected by a combination of active and passive corrosions protection. This combination has proved its value for many decades.

It is generally accepted that the effect of cathodic protection is based on the activation polarization and the concentration polarization [1] of the steel surface resulting in an increase of the pH at the interface between steel and soil (cf. figure 3). This increase in pH value may affect the adhesion of the corrosion prevention coating in the immediate vicinity of the defect. The criterion of cathodic disbondment CD is therefore part of all serious standards for the corrosion protection material of steel pipelines laid in soil and water in conjunction with CP.

Interestingly, the effects of the alkaline environment on layered corrosion protection materials - e.g. polymeric tapes or shrinkable sleeves- have not been the subject of normative considerations yet, although possible damage to the coating material by alkali – here layer to layer adhesion - may pose a significant risk to the pipeline. The same applies for the often-neglected parameter of the shape stability. As long as the delaminated coating rests tightly on the steel surface in the form of a tube (shape stability), no corrosion problems occur [2].

Corrosion can only occur under delaminated coating if a relevant volume is able to push in between the coating and the pipe surface. In other words, if the coating is not dimensional stable or has lost the

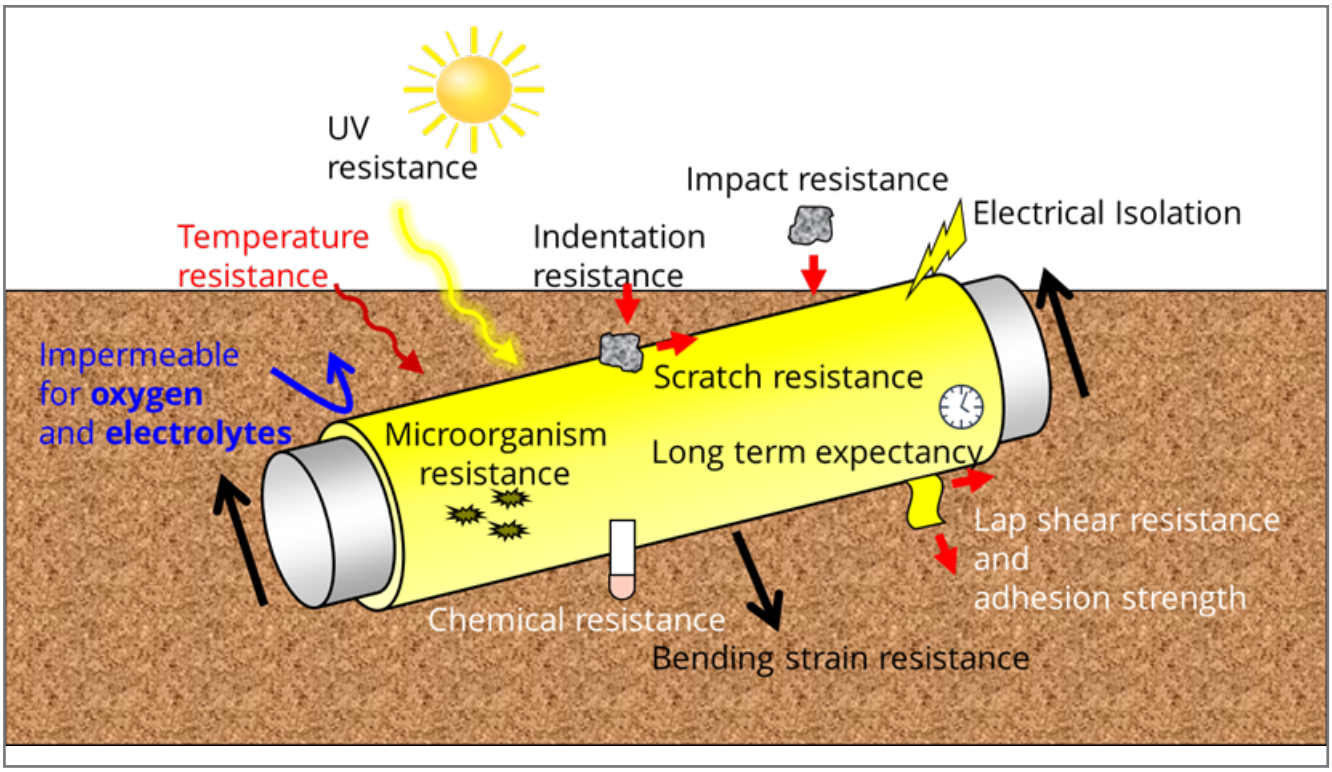


Figure 1: Requirements for a coating

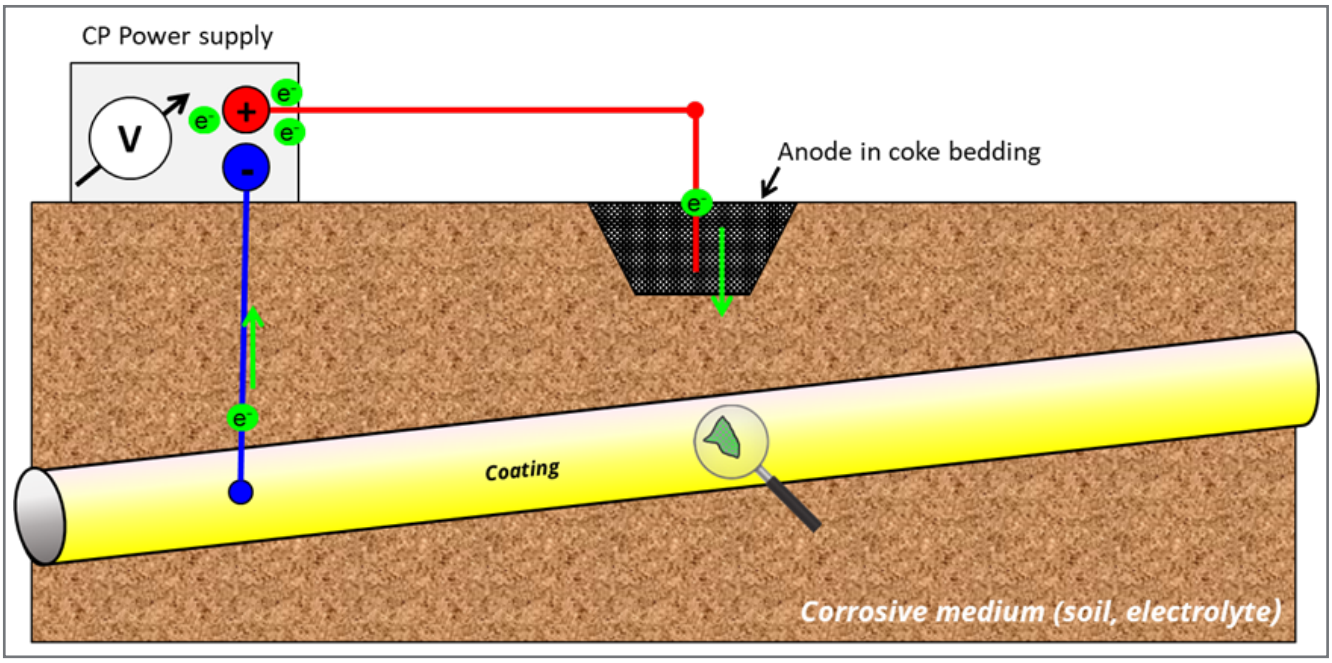


Figure 2: principle of cathodic protection CP

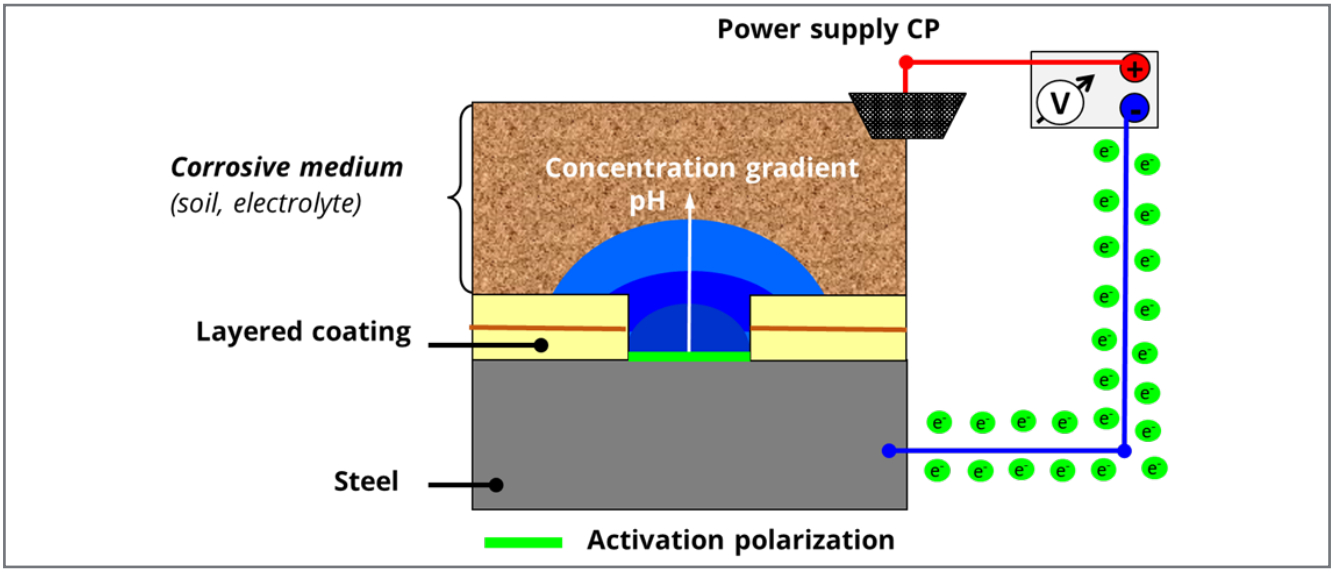


Figure 3 – schematic diagram of the effects of activation and concentration polarization (pH-gradient)/ according to [1]

shape stability, a relevant volume is able to push in between the coating and the pipe surface. As a result galvanic elements are formed in combination with heterogenic aeration (oxygen concentration gradients) resulting in an enhanced local corrosive attack despite of the low oxygen permeation through the coating. In the case of a very low shape stability one even could expect, that a very large and continuous volume between the coating and the pipe surface is formed- in a worst case leading to a flow of oxygen containing water between the coating and the pipe surface.

If the coating parameters layer to layer adhesion and shape stability degrade due to a high pH, i.e. pH > 10, the coating loses its functionality. This is independent of the origin of the high pH, e.g. effect of cathodic protection or the use of fluidized soil.

2. Background / occasion for new survey

There is a plenty of norms and standards for the construction and operation of pipeline structures. Nevertheless, unexpected damage occurs again and test institutes are given the task of investigating their

cause. The field of cathodic protected pipelines is not an exception. Two examples from practice should make this clear:

Example 1: pipeline carrying warm media before bringing into service

The pipeline was designed for a maximum continuous operation temperature of 40 °C. Hot shrinkable tapes were used as the field joint coating. In one segment a liquid soil with a high pH was used in order to increase the stability of the bedding. Before bringing into service a specific electric insulation resistance of the pipeline lower than the limit of 108 Ωm^2 was measured. The result of a further investigation clearly showed, that the affected area is identical to the to that area, where the liquid soil was used.

Example 2: cathodic protected pipeline in operation for a few years

In the course of a routine CP above ground survey, e.g. Direct Current Voltage Gradient [DCVG] Survey, a series of nearly equidistant defects were detected. The distance of the survey points was more or less identical to the pipe length. Therefore, these observations were attributed to defects of the field joint coatings. This was confirmed by several excavations. The inspection of the excavated field joints showed, that the adhesion of the field joint coatings was drastically reduced and only punctual existent. The humidity in the volume between steel surface and coating was high alkaline.

Both examples have in common, that layered corrosion protection systems with test certificates according to DIN EN 12068 were used. Furthermore, in both cases a high alkaline medium was found. Obviously, the specified parameters were not sufficient to exclude future failures.At the first glance this is remarkable, as the respective standards DIN EN 12068, DIN EN ISO 21809-3 or DIN 30672-1 include relevant requirements concerning alkalinity, as for example the cathodic disbondment test. If the presumption is confirmed, these tests are obviously not sufficient to characterize the behavior of these materials in an alkaline environment and to make a reliable statement about their suitability.

This is particularly noteworthy since an alkaline environment inevitably arises when the cathode protection takes effect. The technically responsible process is the formation of the OH ions. The direct consequence of alkali-sensitive materials would be continuous and practically self-increasing damage to passive corrosion protection. This would mean a high-risk potential for the pipelines and would negate the idea of additional protection of a pipeline by the cathode protection in the event of mechanical damage to the casing.

The task was thus to find an explanation for the observed behaviour as well as a simple and meaningful test for the alkali resistance.

3. Preliminary tests - First considerations for testing alkali resistance

DIN EN 12068 already provides a number of requirements, such as the maximum continuous operating temperature, testing of the specific electrical insulation resistance, testing of cathodic disbondment (CD test), testing of the saponification number (without defining the extent of the saponification). These framework conditions were the basis for a new simple test on alkali resistance. There were ideas on other key points that determine feasibility.

- *Duration of test*: The test duration should be as short as possible. One week appeared practice-oriented and desirable.

- *Test temperature*: The maximum continuous operating temperature of the coating must be at least represented the test temperature. With regard to a time-lapse, this may also be increased to a reasonable extent, on the one hand to enable a statement to be made for the test period specified above. On the other hand, thus the significantly longer exposure times to the products in the actual operation of the pipeline can be considered.

- *Concentration of the test medium*: The test of the specific electrical insulation resistance specifies the concentration of the test medium at 0.1 mol / l. Instead of the NaCl solution, a 0.1 molar alkaline solution is used analogously to the test of the saponification number, namely a 0.1 molar sodium hydroxide (NaOH) solution instead of an alcoholic potassium hydroxide (KOH) solution.

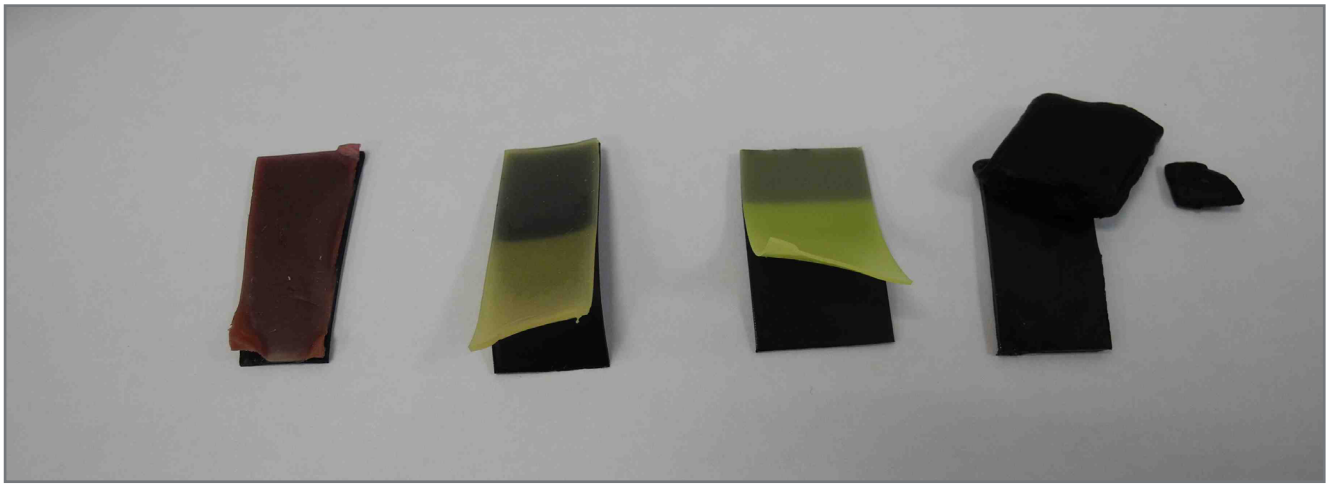


Figure 4: coating materials after one week after one-week storage in 0.1 molar NaOH solution at 50 °C [3]

For a first assessment, a preliminary test was carried out with four samples of different products. For this purpose, the sample pieces are introduced into the described solution at constant temperature without a mechanical load for the named time. The results were very impressive and confirmed the path taken, as the effects were already very different, e.g. the deforming of the samples or impairing the adhesion between the carrier and the adhesive layers. Figure 4 shows the samples after the first preliminary test.

In addition to these obvious qualitative changes, a quantifiable feature was sought that could explain the different behaviour. From other tests, e.g. according to DIN EN 15189, the characteristic of the mass change after storage in various media is known. In comparison to the one-week storage in 0.1 molar sodium hydroxide solution, the corresponding storage in deionate (deionized water) at the same test temperature provides information about the pure water absorption. Since the mass change due to the water absorption in both media, deionate and sodium hydroxide, should be similar, the extent of the saponification can be assessed from the difference of the mass change. Here, saponification is the decomposition of organic molecules or polymers by lye. So, if the mass increase is larger after storage in the alkaline test medium than in deionate, it is not so far off to assess the extent of alkaline induced decomposition of the coating.

Figure 5 shows the mass difference in the two media sodium hydroxide solution (ΔNaOH) as well as deionate (ΔH2O). The logarithmic scale in the right picture facilitates the evaluation and classification of the values. For samples C and E, the mass changes are less than 0.5%. These samples can be considered as resistant to saponification. For the other three samples A, B and D, on the other hand, the differences in both test media are large and, therefore, clearly indicate a saponification.

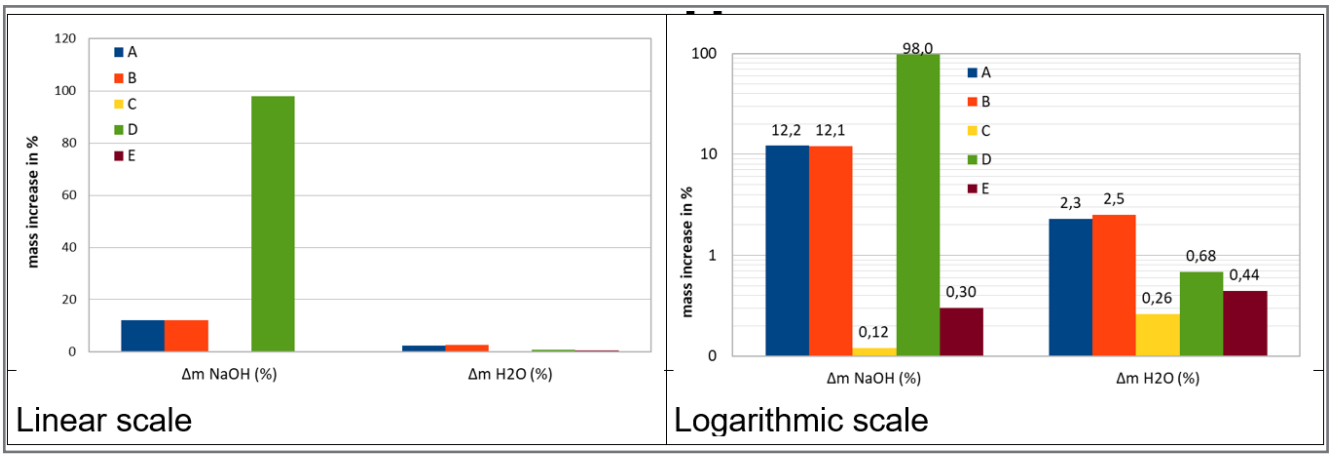


Figure 5: mass difference of field joint coatings after one-week storage in 0.1 molar NaOH solution and deionate at 50 °C [3]

4. interlaboratory tests - systematic investigations

The results of the preliminary tests thus substantiated the first assumptions and called for a further and broader investigation for further confirmation. A reliable statement is only permissible with a broad basis and is mandatory for the acceptance of an additional requirement and test. For the aforementioned reasons, a simple, quick test was developed under the umbrella of the DVGW together with experts and corrosion protection experts from pipe network operators, test institutes and product manufacturers [4]. The test, that will be carried out in a short-term test of 7 days at elevated temperature, provides a statement about the relevant behaviour. An additional test temperature of 80 °C was added to the test temperature of 50 °C, which is the standard temperature for field joint coatings according to DIN EN 12068. On one hand, this temperature corresponds to the maximum continuous operating temperatures of factory coatings, which are quite common today, and on the other hand represents the time lapse already mentioned compared to 50 °C.

The following criteria were defined as the subject of the investigation:

1. The bond between adhesive and carrier,
2. Changes in the carrier or coating material
3. The determination of the mass change after storage for one week in deionized water and sodium hydroxide solution.

4.1 test description:

Storage media: deionized water and 0.1 M NaOH solution

Storage temperature: 50 °C and 80 °C

Storage period: 1 week / 1 w

3 samples (e.g. 10 mm x 50 mm) are required for each test series:

Series 0: reference sample, no storage in water or caustic soda

Series A: deionized water at (50 ± 2) °C

Series B: 0.1 molar NaOH at (50 ± 2) °C

Series C: deionized water at (80 ± 2) °C

Series D: 0.1 molar NaOH at (80 ± 2) °C

In the first interlaboratory test, 11 different tape stripes from 6 manufacturers from Europe, North America and Asia were tested.

4.2 Test procedure:

The samples are completely immersed in deionized water for one hour, then dabbed with a lint-free cloth and weighed (weight in grams). They are then freely suspended, but completely immersed in the appropriate media. Wires are used to store the samples so that the contact area is as small as possible (cf. figure 6). The covered containers with the samples are laid into heat chambers with the appropriate temperature. After a week, the samples were removed, rinsed with deionized water, blotted with a lint-free cloth and immediately weighed (weight in grams). The difference between the weighed-out and weighed-in results in the mass change in grams were measured.

The surfaces of the carrier and adhesive are checked for visual changes and documented photographically.Special changes such as softening of the materials, impairment or loss of shape stability must be described and, if possible, documented photographically.Then the bond between the carrier and the

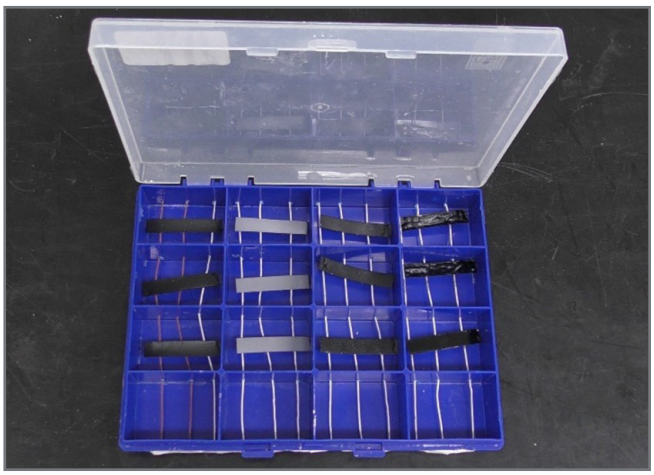


Figure 6: Open sample container for storing multiple samples at the same test temperature [3]

adhesive is checked manually and the fracture pattern is documented.

4.3 Results

Figure 7 shows four specimens of the considerable range of results.

a. no change

b. adhesive gets bubbles and softens extremely, so that there is no longer any adhesion to the carrier foil, i.e. easy detachment

c. highly softened

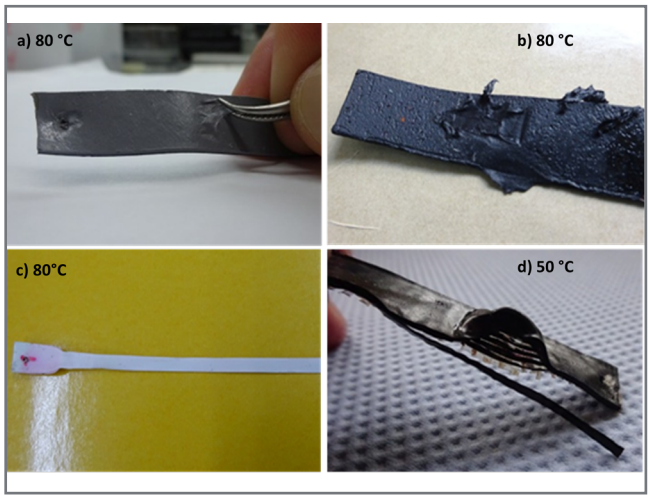


Figure 7: Examples of four specimen after one week of storage in NaOH

d. highly softened and very easy peeling off

A "traffic light display" was therefore defined in order to classify the different behavior with three colours (see table 1). It has been shown that the results of the traffic light display from different test institutes match well.

The results of the investigations carried out so far can be summarized as follows

- There are significant differences in the behaviour of the products (cf. Figure 4)
- The results range from:
  - No or almost no changes
  - Noticeable loss of the adhesion between the adhesive and the carrier film
  - Softening of the carrier film and thus loss of shape stability
  - Loss of stability of the adhesive
- In some cases, the damage patterns mentioned were observed simultaneously

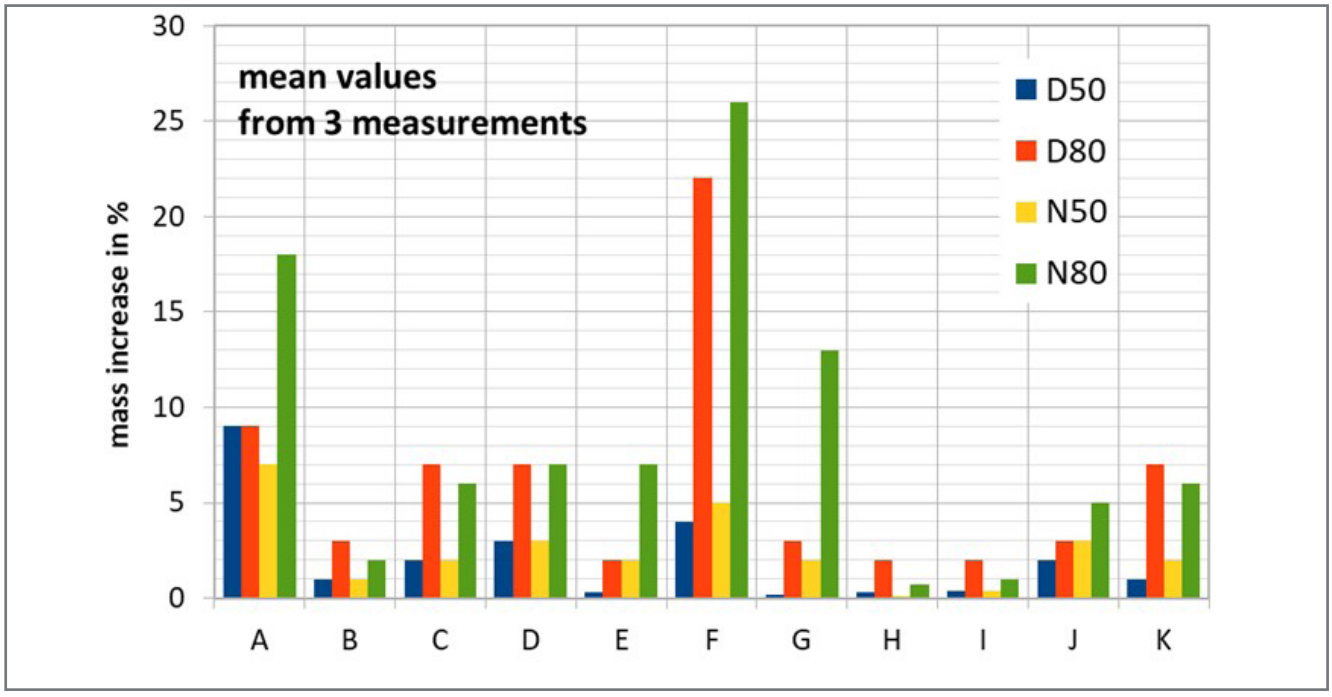


Figure 8: Results of the mass change [3] - 50 or 80: test temperature in °C | D: deionized water | N: 0.1 M NaOH

		Evaluation of the adhesive layer after one-week storage	
Test sample	Temperature	in H_2O	in 0,1 M NaOH
A	50 °C	no change	no change
	80 °C	minimal softening of the carrier foil	minimal softening of the carrier foil
B	50 °C	no change	no change
	80 °C	no change	no change
C	50 °C	no change	no change
	80 °C	no change	no change
D	50 °C	no change	adhesive gets bubbles and softens, so that the adhesion to the carrier foil is decreased significantly
	80 °C	adhesive gets bubbles and softens extremely, so that there is no longer any adhesion to the carrier foil	adhesive gets bubbles and softens extremely, so that there is no longer any adhesion to the carrier foil Additionally, the shape stability of the carrier film is impaired
E	50 °C	no change	Bubble formation in adhesive
	80 °C	Bubble formation in adhesive	Bubble formation in adhesive
F	50 °C	Bubble formation in adhesive	Bubble formation in adhesive
	80 °C	adhesive gets bubbles and softens, so that the adhesion to the carrier foil is decreased. Additionally, the shape stability of the carrier film is impaired.	adhesive gets bubbles and softens, so that the adhesion to the carrier foil is decreased significantly
G	50 °C	Bubble formation in adhesive	Bubble formation in adhesive
	80 °C	Bubble formation in adhesive	Bubble formation in adhesive und distinct softening effect. Bond to carrier foil however is acceptable.
H	50 °C	no change	no change
	80 °C	no change	no change
I	50 °C	no change	no change
	80 °C	no change	Bubble formation in adhesive
J	50 °C	Bubble formation in adhesive	Bubble formation in adhesive
	80 °C	Bubble formation in adhesive	Bubble formation in adhesive und softening effect
K	50 °C	Bubble formation in adhesive	Bubble formation in adhesive
	80 °C	Bubble formation in adhesive	Bubble formation in adhesive und softening effect

Table 1: Traffic light display [3] - Green: no change; Orange: optical observation does not impair functionality; Red: Failure of the tape with regard to one of the criteria of adhesive bonding and shape stability

The presence of one of these failures only leads to failure of the corrosion protection effect, i.e. either loss of adhesion between adhesive and carrier film or loss of shape stability.

- A comparison of the traffic light displays with the measurement results of the mass increase (see Figure 8) indicate a possible correlation between the extent of the material change and the increase in mass.
- The visual impression and the observed shape stability immediately enable an evaluation of the property of interest.

5. Summary

- An alkaline environment can have different causes, e.g. a coating defect at a cathodic protected pipeline
- The shape stability of corrosion protection materials is an important prerequisite for ensuring permanent corrosion protection.
- The influence of an alkaline environment on the shape stability as well as the layer to layer bond of corrosion protection materials is of great importance.
- The results of the CD test provide no or only insufficient information about this effect.
- Despite good values in the CD test, corrosion protection materials can behave completely differently with regard to the effects on their shape stability.
- The test described here is simple, can be carried out in a short time and without expensive equipment or special knowledge. It gives a very good impression of the expected behaviour of the materials when used in an alkaline environment.

6. Conclusion

The quality and long-lasting lifetime of a coating system is largely determined by the choice of raw materials, the compatibility with each other and the persistence against the boundary conditions, that are affecting or prevailing during use. A simple test can be used to check a previously little-considered but important property for everyone. This test is easy to carry out and understandable. This makes it easy to identify inferior or less suitable systems by means of a fast and simple test.

7. Outlook

The possible influences of the surrounding area examined here on the cut surface, in the case of continuous defects, of layered corrosion protection systems, such as tape systems or heat-shrinkable sleeves, have so far not found their way into the known national and international standards for the specification of field joint coatings.For this reason, interlaboratory tests were started under the umbrella of the DVGW with the cooperation of experts, test institutes, pipe network operators and product manufacturers [4]. The knowledge gained is gradually presented to the professional audience. On the basis of this, corresponding requirements for coating systems are to be formulated and included in the relevant national and international standards.

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The Feeder 9, River Humber, replacement pipeline project, United Kingdom

W.KOOP[1]; M. LUBBERGER[2]; T. JAGUTTIS[3] > A.HAK INTERNATIONAL[1]; HERRENKNECHT[2]; DE LA MOTTE & PARTNER[3]

Abstract

The Feeder 9, River Humber Pipeline project is required to replace the existing Feeder 9 gas pipeline with a new 1,050 mm high pressure gas pipeline under the estuary of the River Humber. To avoid any impact on the local environment, the pipeline will be installed inside a pre-cast concrete lined tunnel. The tunnel is being excavated utilizing a 4.4 m diameter Slurry Pressure Balance Machine to provide a tunnel of 4.9 km in length with an internal diameter of 3.65 m.

Following completion of the tunnelling works the pipeline is inserted as a continuous 4,992 m string into the water filled tunnel before connecting at each end to the existing Feeder 9 pipeline. Despite the huge technical challenges involved in this project, the project team in collaboration with National Grid, have developed a solid technical solution to the installation of a circa 5 km pipeline into a flooded tunnel, an achievement that has not been equaled anywhere in the world, which gave a registration in the Guinness Book of records!

This EPC-project was commenced in May 2016 and will be fully completed by August 2021.

A 5km pipeline 48" inserted into a tunnel under the River Humber - A new record

1. Project Overview

A strategic component of the United Kingdom Gas National Transmission System (NTS) is the Feeder 9 pipeline that crosses the Humber estuary near Kingston Upon Hull.

In 2009, underwater surveys highlighted an unprecedented amount of erosion near Feeder 9 which had exposed sections of the pipeline in the navigation channel. It was necessary to find a long-term solution for this Feeder 9 pipeline. A tunneled solution was determined to be the most; economical, environmental, and safe way to proceed.

The Feeder 9 pipeline project, upon completion in 2021, will be the longest pipeline in a tunnel in the world and will transport up to 20% of the UK gas supply.

The new pipeline will not be subject to the uncertain conditions of the Humber Estuary and will thus ensure the reliable and safe transportation of gas for the foreseeable future.

As well as being economically significant, the Humber Estuary and the intertidal mudflats surrounding the area are of significant ecological importance for many species including birds, mammals (seals and otters), and fish. As such it is afforded some of the highest levels of environmental protection available through International, European and National legislation. The Humber Estuary is an internationally a European designated Special Area of Conservation (SAC), a Special Protected Area (SPA), a nationally designated Site of Special Scientific Interest (SSSI) and an Important Bird Area (IBA).

Scope of this Project is:

- Construction of a concrete lined tunnel up to 30m deep below the Humber for nearly 5 km
- Installation of a 1,050 mm diameter concrete weight coated pipeline with a maximum operating pressure of 70bar
- Connection of the new pipeline to the existing connections approximately 120 m onshore at Goxhill and 400 m at Paull
- Decommissioning of the existing Feeder 9 pipeline
- Cathodic protection facilities for the new pipeline
- Two construction compounds, one each side of the river at Goxhill and Paull, adjacent to the existing AGIs
- Significant environmental works to mitigate the impact on the existing protected environment
- Associated works for permanent and temporary accesses, highway works, drainage works, temporary spoil storage, temporary lay-down areas and ancillary works

The pipeline is designed to have a minimum operation life of 40 years and the tunnel a minimum design life of 120 years.

2. Tunneling Activities

The tunnel between the launch pit in Goxhill and the reception pit in Paull has an overall length of 4,862 m and follows a nearly straight horizontal alignment. The planned vertical alignment follows a decline of the gradient of approximately 4% for a length of 450 m. Beneath the estuary the tunnel drive is virtually horizontal and will revert to an inclined gradient of approximately 4% on the north bank of the estuary for the last 600

m. Excavation is mainly within the Burnham and Flamborough with a minimal overburden to the seabed of approximately 10 m. However, within the launch pit and reception shaft the tunnel passes through layers of the Alluvium and Glacial Deposits.

3. Pipeline Insertion

Following completion of the tunnelling drive and strip out of the tunnelling services preparations will begin for the pipeline insertion. No pipe welding activities are possible within the tunnel and therefore the pipes (each 12 m long) will be welded into strings of between

612 m and 624 m on the surface whilst tunnelling activities continue.

The pipes have been delivered to site by truck and are made up of two different types; concrete weight coated (CWC) for installation inside the tunnel with a pipe weight of 16 tons, and fusion bonded epoxy (FBE) coated pipe for installations outside the tunnel with a pipe weight of 5.9 tons.

Unloading and stockpiling in the pipe lay-down area was carried out utilising a crane with a vacuum lifter for the FBE pipes and traditional lifting equipment for the CWC pipes. In the pipe stringing yard eight strings will be constructed providing two lines of 624 m in length and six lines 612 m in length, Figure 8: Installation of the pipe strings in the pipe stringing yard. The pipes will be semi- automatically welded allowing for a tolerance or misalignment of 0.5°. All welds will be inspected and tested using automatic ultrasonic testing.

A total of 13 winches or strand jacks will be used to move the pipe strings laterally on bogies across the foundations in the yard. The bogies run on a rail system which will be laid perpendicular to the line of insertion.

Prior to the insertion of the pipes into the tunnel the following activities must be completed:

1. Strip out/Removal of all utilities from the tunnelling works
2. Installation of cathodic protection (CP) equipment (monitoring cables, anodes with power cables, reference cells)
3. Installation of a gravel bed
4. Installation of an internal ramp at Goxhill
5. Partial construction of a tunnel bulkhead at the launch shaft in Goxhill
6. Filling the tunnel with water

The pipe string will then be winched from the stringing yard to the pipe thrusters in the launch ramp. Prior to installation of the pipe the tunnel is filled with water and a bulkhead installed at each end. The total amount of water required is approx. 51,000 m³ and will be supplied from either the local potable water supply or boreholes.

Two pipe thrusters with a capacity of 750 tons and 500 tons will be installed in the launch ramp to push the pipe gently into the tunnel and as the first section is pushed into the tunnel a tie-in weld to the second string will be completed. In total seven tie-in welds are required before the pipeline is completely inserted into the water filled tunnel.

4. Conclusion

The project delivery phase for the Feeder 9 pipeline replacement, which will be the longest pipeline in a tunnel in the world, has passed all it's key milestones to completion.

Despite the huge technical challenges involved in this project, the project team in collaboration with National Grid, have developed a solid technical solution to the installation of a circa 5 km pipeline into a flooded tunnel, an achievement that has not been equaled anywhere in the world. Not only will this project set the bar in respect to overcoming technical challenges never before encountered it will provide a long-term sustainable solution to the transmission of gas across.

A new Gas Pipeline under River Humber: The role of small diameter tunneling for pipeline installations

1. Introduction

Different points of view of all involved parties have to be considered when it comes to the planning of pipeline routes and the evaluation of potential installation technologies. Due to a rising public attention paid to environmental issues and landowners´ concerns, the impact of pipeline construction on the surroundings has to be reduced to a minimum. While a large proportion of cross-country pipeline installations are still executed by conventional open-trench methods, trenchless technologies are mostly considered for

sensitive crossings of water and traffic routes or pipeline landfalls.

In order to create a reliable and sustainable pipeline network for the upcoming decades, existing pipelines have to be expanded and new pipeline capacities have to be built. Innovative construction methods are needed to fulfill the project requirements, to match the time schedule and to comply with environmental regulations and concerns. Different trenchless pipeline construction methods are available to cross existing surface and sub-surface obstacles along the route in a safe, effective and environmentally acceptable manner. Innovative technical concepts enable these technologies to be used also in the construction of outfall structures and pipeline landfalls. Whereas in conventional HDD or Direct Pipe® the product steel pipeline is installed directly in the ground, methods from the tunnelling industry provide pipe jacked or segmentally lined casing tunnels in which the pipeline is installed in a second step. This paper will focus on the role of small diameter segment lining TBM (up to approx. 4 m internal diameter) for pipeline projects on the given reference pipeline project Feeder 9 under the river Humber.

2. Small Diameter Tunnels for Pipeline Installations

Tunnelled solutions are often considered for challenging & long crossings or the landfall sections along the pipeline route. Conventional pipeline installation methods like HDD come to their geological limits in highly permeable soil, under high groundwater pressures or with low soil coverage. Of course, Direct Pipe® presents an alternative to install a pipeline in one step in the ground using Slurry Microtunnelling in combination with the Pipe Thruster technology. In 2020, a Direct Pipe® distance record was set in New Zealand with 2,120 meters installing a 48" pipeline. For even longer drives, through changing ground conditions or with high overburden, tunnelled solutions often present the only choice in order to procure safety and reliability in pipeline installation.

In North America, several pipeline sections are currently in discussion to be tendered as tunnelled casings as there is no other choice to overcome complex ground conditions or long distances through mountains with high overburden.

2.1 Machine technology overview

Concerning the machine concept, various factors must be considered to choose the best-suited tunneling technology for a specific pipeline crossing project, such as geology, tunnel length, curve radii and installation depth. Within this process, the detailed analysis of the geotechnical report is the most important deciding factor. According to geology and requested diameter the following machine types are available for pipe jacked and segmentally lined pipeline casing tunnels. In order to increase versatility in tunnelling, combined shield concepts have been developed in the past to cope with changing soil conditions along the tunnel route.

2.2 Machine concepts and face support

In mechanized tunnelling, there are three different shield types: Slurry shields, earth pressure balance shields (EPB), and open shields. Each of these proven

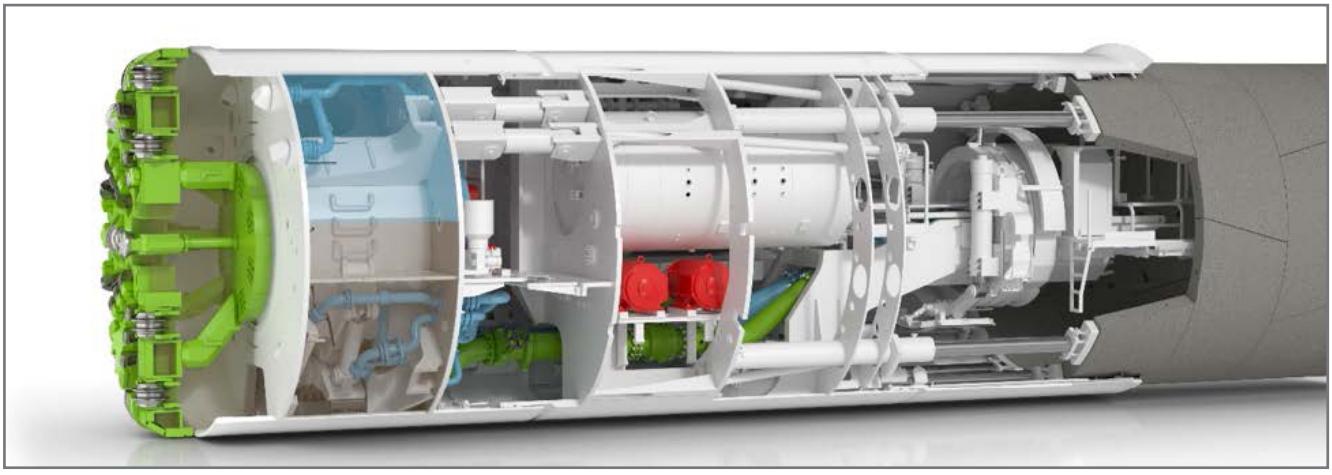

Figure 1: M-2141M_Mixshield 4340 for Humber Crossing

methods has advantages within its special range of application in certain ground conditions. Slurry shields and EPBs work with a closed pressure system to actively support the tunnel face by slurry or excavated soil. In varying ground conditions, specially adapted and combined shield concepts are advantageous, but are not further discussed in this paper.

2.3 Slurry / Mixshield machines

A slurry shield machine is most economical in sandy and gravel ground conditions. The most common machine type for pipe jacking operations with the broadest range of application in terms of ground conditions and hydrogeology is the slurry based AVN and AVND (with air cushion) technology with a market share of over 85%. This machine range is characterized by a cone-shaped crusher inside the excavation chamber that crumbles stones and other obstructions to a conveyable grain size. For Mixshield machines from 4 m shield diameter onwards, it is more common to use a jaw crusher instead of a cone crusher.

2.4 General tunnel lining procedures

Tunnel and surrounding ground behind the tunnelling machine require immediate support. Two different lining methods are proven technology in tunnel construction: Pipe jacking and segment lining. Segment lining has a long tradition in mechanized tunnelling. The principle of ground excavation by TBM and consecutive ring building are well known in the construction industry. Segment lining offers a high degree of flexibility concerning the planning of tunnel routes. Long drives and tight curve alignments are possible. The erection of the segment rings takes place in the rear part of the machine. Thus, the tunnel is built directly behind the tunnelling machine. The annulus between the ring extrados and ground is backfilled with grout. However, the minimum diameter for segment lining tunnels is increasing due to restrictions given by tightened safety regulations.

2.5 Safety standards in tunnelling

During the last decades, safety aspects in mechanized tunnelling gained more and more importance and safety standards are consequently improved: starting from basic topics such as PPE (Personal Protective Equipment) and space requirements, including refuge chambers and detailed rescue statements. From a European point of view, the latest tunnelling safety standards are summarized in DIN EN 16191:2014, which is currently being reviewed to even improve health and safety conditions by taking into consideration lessons learnt. The latest ´DIN published in 2014 tightened regulations in regards of machine diameter and accessibility, also considering several other aspects as rescue systems and fire protection. This lead to confined space conditions in the machine, especially where segment lining logistics have to be considered. European manufacturers of tunnelling equipment must comply to European regulations and the leading DIN EN 16191.

The logistic is the main key for a good overall performance on a segment lining TBM. A California crossing inside the tunnel is often needed for segment lining tunnels to allow trains to pass in order to reduce delays due to the travel times of the train. On the California crossing two trains can pass each other and an escape route along the California needs to be maintained at all times. The segment length is generally not less than 1000 mm to keep the number of joints and segment seals to a minimum and to improve production. Furthermore, the smallest standard locomotive has a width of 1 meter. Considering a California crossing with two trains of 1000 mm in width and a sufficient escape route a minimum inner diameter of approximately 2850 mm is required.

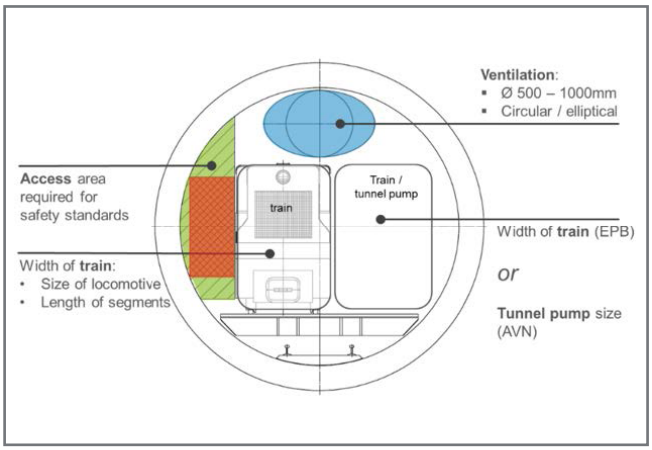

Figure 2: General cross section of small diameter Segment Lining TBMs

To allow enough space for a ventilation duct and the necessary tunnel lines, an inner diameter of 3000 mm becomes the preferable size for segment lining tunnels with a certain length. In order to achieve an optimal use of the available space on the California crossing, it may then be possible to increase the segment length to 1200 mm. The compromise is that two fully

loaded trains with 1200 mm segments cannot pass on the California crossing.

2.6 Drive length and ventilation

The maximum achievable single drive length is driven by several factors. One factor is the logistics for the supply of the TBM with the necessary material such as segments and consumables. Another even more important factor is the logistics for the mucking of the excavated material. An optimized logistic concept might require California switches to allow trains to pass inside the tunnel. Ventilation for the TBM and the tunnel has to be maintained at all times, and this may also affect the limits in drive length.The required ventilation volume of fresh air is specified in local regulations.

The following Table gives a rough overview for the maximum air duct size for different tunnel diameters. The table also shows the possible drive length considering a minimum air flow of 0.3 m/s in the free section of the tunnel and a maximum pressure of 6,000 Pa in the air duct. For example, a tunnel with a length of 8 kilometers can be built (and this has already been done) with a 3000 mm inner diameter tunnelling machine and an air duct of 1000 mm. Please note that the figures in the table are only rough estimations, which depend on individual project and design parameters.

Internal Diameter	Air Duct Diameter	Possible Drive Length
2,500 mm / 8 ft	500 mm / 20 in	2,000 m / 1.2 mi
2,500 mm / 8 ft	700 mm / 28 in	4,000 m / 2.5 mi
3,000 mm / 10 ft	700 mm / 28 in	3,500 m / 2.2 mi
3,000 mm / 10 ft	1,000 mm / 40 in	8,000 m / 5 mi
3,500 mm / 11.5 ft	1,200 mm / 48 in	10,000 m / 6.2 mi

Table 1: Guideline of diameter, air duct size and drive length (without booster fans in tunnel, without any diesel power in the tunnel)

For an efficient design and planning of a tunneling project with a given drive length, all these parameters have to be considered to define the optimum tunnel diameter, air duct diameter and minimum cross section for emergency purposes as described and sufficient size to accommodate the rolling stock for material supply and discharge. If a slurry TBM is chosen for the project, then the slurry pumps and lines in the tunnel need to be considered in addition to other tunnel lines, such as power supply, compressed air, cooling water and discharge water.

3. Reference Project: River Humber Crossing, United Kingdom

The new gas pipeline under River Humber replaces the existing Pipeline 9 which was laid in a trench just below the river bed, exposed to shifting tides. The pipeline replacement project consists of a segment lining tunnel which will house a 42" gas pipeline to connect the national network in Goxhill in North Lincolnshire to Paull in East Yorkshire, where the gas comes onshore. The 4,862 meter long tunnel runs with 10 meter coverage below the Humber River bed. With a slope of up to 4% in both riverbank areas, the tunnel alignment is situated in chalk, alluvium and glacial deposits. The main challenge in tunnel construction was the length of the tunnel section without intermediate shaft, with impact on detailed planning and design for working safety and logistics in this relatively small inner tunnel diameter of 3650 mm. A Mixshield Slurry TBM with a shield outer diameter of 4340 mm was used for the project. Logistics have been handled by a Multi Service Vehicle (MSV), not by a rail-bound locomotive, which was a premiere in England for this diameter range. A sophisticated safety concept was implemented to assure additional worker safety at all times during the tunnelling progress.

3.1 Pipeline Installation with Pipe Thruster

After completion of the tunnelling works, all tunnel installations were removed from the tunnel. For safety reasons no welding in tunnel was authorized to connect the 12 meter concrete coated pipe sections. The new 42" gas pipeline has been installed in the segment lining tunnel using two Pipe Thrusters with 500 and 750 Tonnes of push force. A total of eight pipe sections have been laid out on Goxhill site and welded together to two 624 meter and six 612-meter-long sections. Two Pipe Thrusters were installed in the shaft area. The tunnel was flooded to reduce the push forces by the buoyancy force of the pipeline. In July 2020, the new pipeline has been completely installed in the tunnel, setting the world record for the longest hydraulically inserted pipeline.

Pushing pipelines into existing tunnels (created by Pipe Jacking or Segment Lining technology) with the Pipe Thruster is becoming more and more common in the pipeline industry. This method has already been implemented in several projects worldwide, with its

Figure 3: Pipe Thruster clamping the 42" pipeline for insertion in segment lining tunnel

premiere in Australia, where 750 Tonne Pipe Thruster was used to install the 14,270 feet (4,350 meter) long pipeline in a segment lining tunnel in 2014.

Pushing the Limit - Pipeline Installation Design Aspects

1. Introduction

Pipe9 JV, a cooperation of Skanska UK, Porr and A.Hak, had been awarded by National Grid with the contract to design and construct the Feeder 9 gas pipeline replacement under the River Humber, UK.

The specialist design services for the installation of the pipeline into the 5 km long tunnel were provided by de la Motte & Partner for Pipe9 JV.

The client's front-end design comprised a segmentally lined tunnel of 3.5 m internal diameter with a 40" diameter FBE coated high pressure gas pipeline installed on roller supports.

After the pipeline installation the tunnel was to be flooded with water for the operational phase, to allow for future modifications or repairs.

With their tender Pipe9 JV proposed for a 'wet installation' of the pipeline an alternative construction method, which was considered to offer several advantages over the initial design but also included the challenge of setting a new record for this method of pipeline installations.

2. Pipeline Tunnel Cross Section

In general, the proposed 'wet installation' of the pipeline is based on the concept of moving the pipeline into a flooded tunnel, thus reducing its effective weight by buoyant forces. Further it was intended to push the complete pipeline into the tunnel rather than pull in order to utilize the space of the tunnel launch shaft and improve control of the string handling and movement during installation.

Several installation options were assessed in close cooperation with the client's engineers as part of the design process in order to achieve pipeline stability during the operation while at the same time minimizing the effective pipeline weight for the installation phase. Figure 4 shows the tunnel cross section of the final installation option with the pipeline resting on the tunnel invert. The selection of materials for this configuration was restricted to the client's qualified solutions and strongly driven by the cathodic protection system

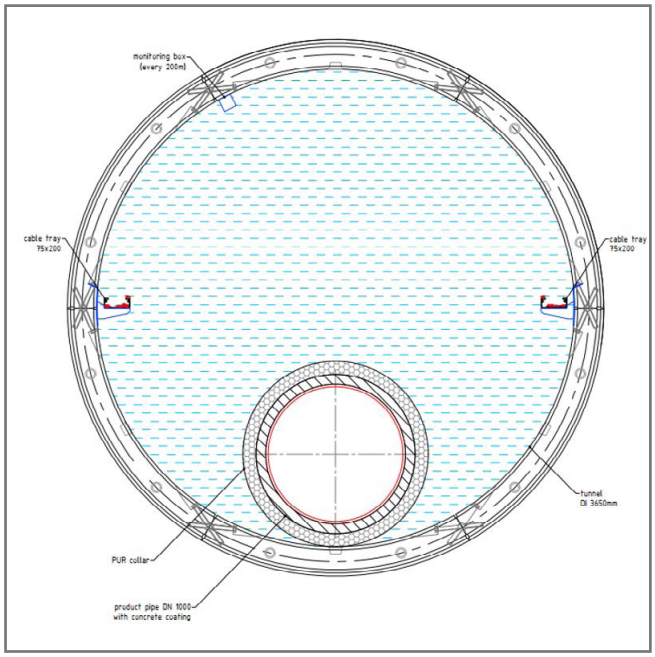

Figure 4: Tunnel cross section

Figure 5: Friction test

– an impressed current system, with several anodes and monitoring points installed along the tunnel's inside.

Aside from the 1067 x 22.1 mm pipe with an FBE coating the final solution comprised a 75 mm concrete weight coating of 3040 kg/m3 density for negative buoyancy as well PUR collars at approx. 6 m spacing to reduce friction during the installation.

In summary, the effective weight of the pipe strings amounted to approx. 13 kN/m in dry and 1.4 kN/m in submerged conditions.

2.1 Installation design

The tunnel cross section as outlined above had been selected during the design phase as a 'compromise' in order to meet the contradicting requirements of a sufficient operational stability (heigh weight), acceptable installation forces (low weight) and a maximum safety against buckling (hight weight, low friction), which could occur at high push forces if the restoring forces from pipe and tunnel geometry are too low to prevent an increasing lateral deflection of the pipe.

Aside from knowledge of the friction between the pipe string and tunnel wall, accurate information of the effective submerged pipeline weight is required for an assessment of installation forces as well as critical loads. Several tests have been carried out to narrow the uncertainty of this data, such as friction tests (Figure 5), sampling of water densities and inspection of pipe and coating weights and dimensions.

A total installation force of approx. 4000 kN had been determined from this information for the complete installation over 4850 m length as shown in Figure 6, the subsequent welding and installation of eight partial pipe strings resulting in a characteristic saw-tooth shape of the push force.

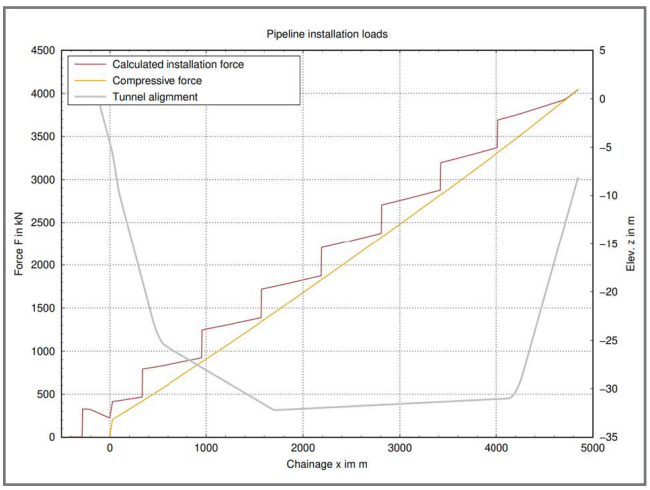

Figure 6: Installation loads

The compressive force required to push the pipe section inside the tunnel is determining the risk of string buckling, which had been assessed by additional FE models also considering the effect of the of the

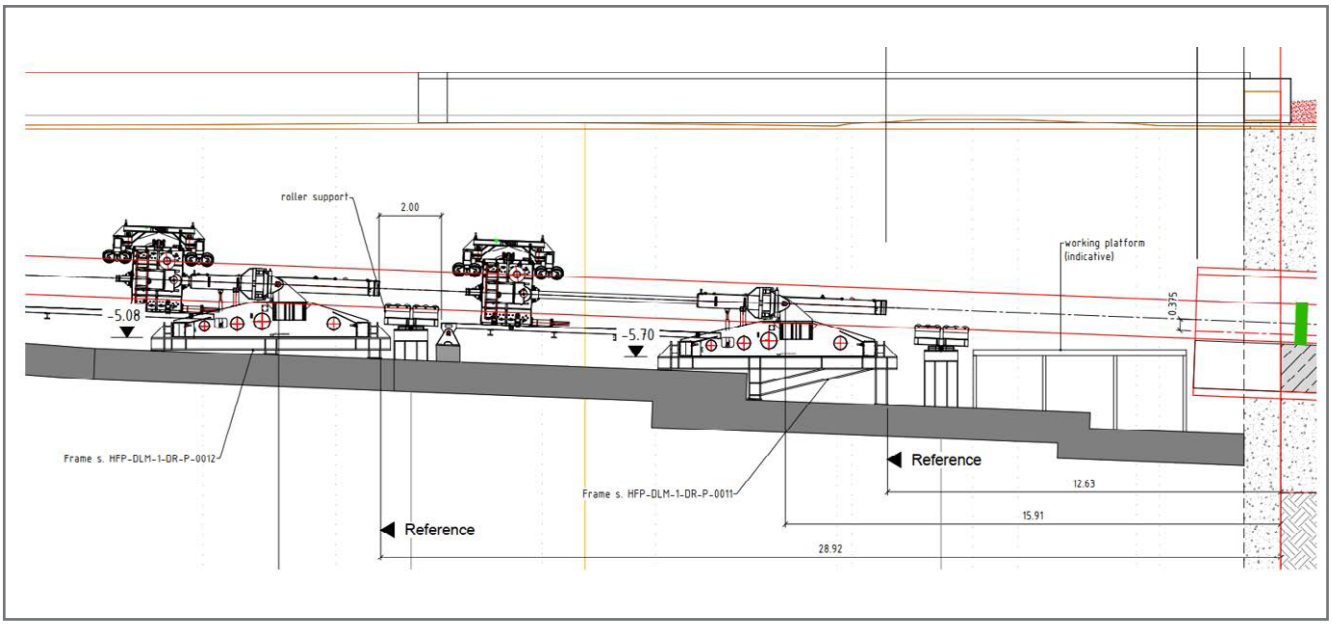

Figure 7: Shaft installations / Pipe Thruster

concrete weight coating onto the pipe's stiffness. To move the pipeline into the tunnel, a twin setup of Pipe Thrusters had been designed inside the tunnel launch shaft (Figure 7). The base frames for these devices were designed for their full capacity of 7500 kN and to introduce the reaction forces into the base slab of the shaft.

To ensure that push and clamping forces of the Pipe Thrusters can be introduced through the weight coating into the pipeline, shear tests had been carried beforehand.

As-Built surveys were taken after completion of the tunnel construction and prior to pipeline installation to the verify design assumptions and assess possible pipe spanning from misalignments of the tunnel invert as well as increased friction from segment misalignments.

2.2 Construction data

With the information of the as-built surveys a forecast of the minimum and maximum range of installation loads had been derived and a monitoring regime was defined to update and refine this forecast during the pipeline installation process.

The operation data of the Pipe Thruster was logged electronically and processed off site to provide updated results and limit values for each shift briefing. A record of the installation loads is given below in Figure 8.

The averages of the recorded data coincide well with the anticipated installation loads and the increasing distribution of these data points is an indication of 'minor' effects such as stick-slip friction and axial compression of the pipe string. Although these effects may generally be assessed qualitatively during the design phase, a quantification may not be possible due to the uncertainty of the contributing factors.

In conclusion, the push installation of the Feeder 9 replacement pipeline had been carried out successfully, setting a new record in length. However, it is also evident that even after significant efforts in testing, surveying and modelling effects that are commonly disregarded minor amount to a substantial fraction of the design load.

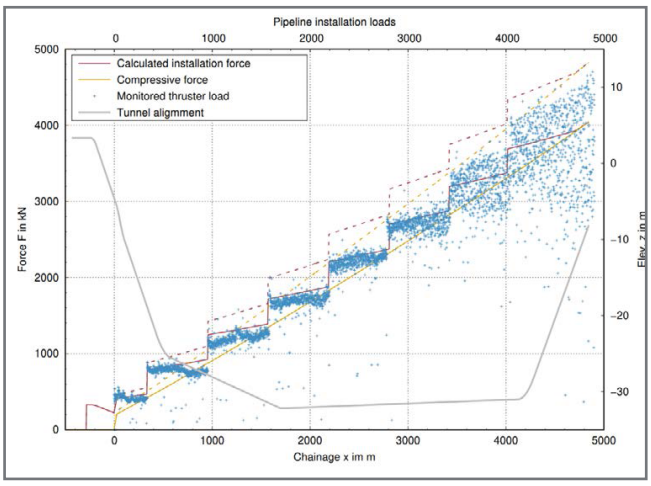

Figure 8: Monitored installation loads

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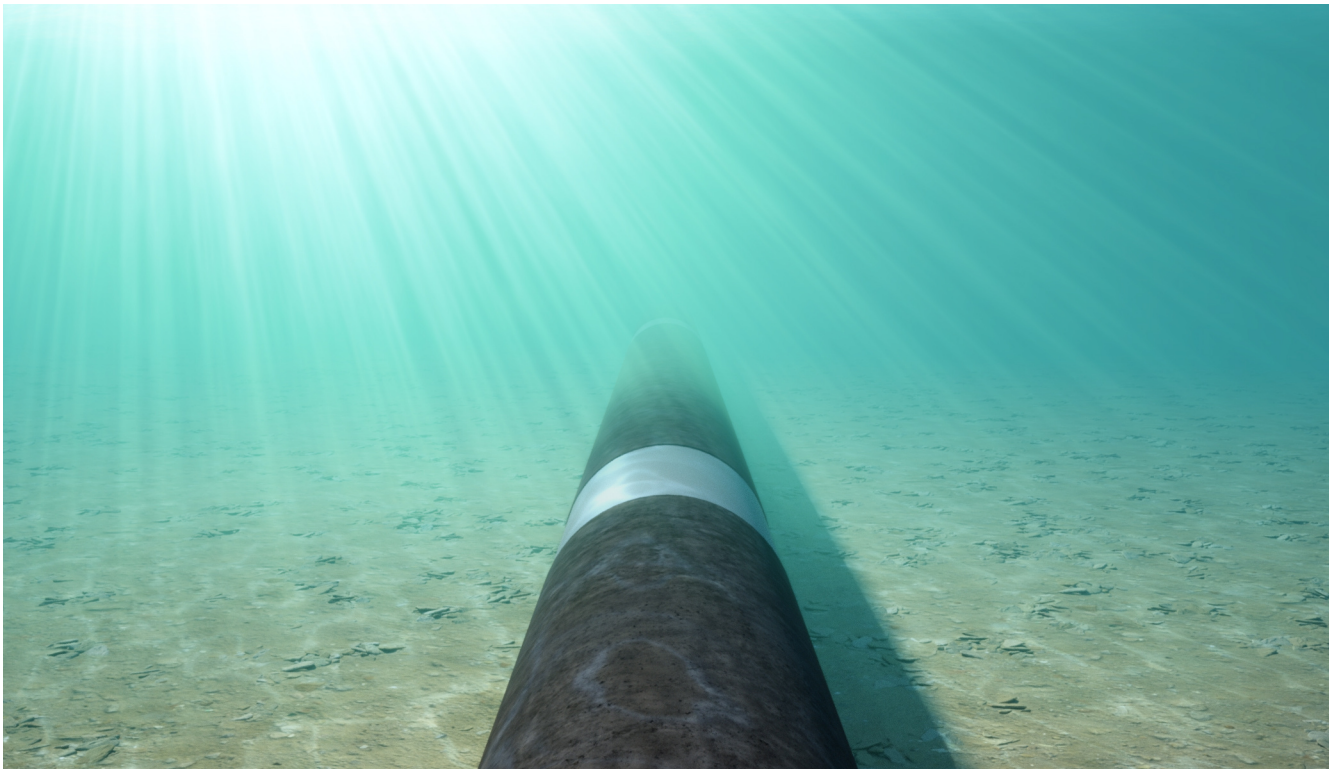

Safely repurposing existing pipeline-infrastructure for CO_2 transport – Key issues to be addressed

E. ØSTBY, L. E. TORBERGSEN, S. RØNEID, B. H. LEINUM > DNV HØVIK-NORWAY

Abstract

In the context of carbon capture and storage (CCS) or utilization (CCUS), offshore pipelines are foreseen to play an important role for the transport of large quantities of carbon dioxide (CO_2) from sources sinks/consumers. There is currently a strong interest within the industry to explore the possibility for repurposing of existing pipeline infrastructure to leverage on existing CAPEX investments. Even though this may seem attractive from a cost perspective, the technical, safety and financial risks need to be acknowledged and addressed accordingly. Several decades of industry experience exists for onshore CO_2 pipelines, mainly for enhanced oil recovery (EOR), however, the experience is rather limited for offshore pipelines. Change of product will per applicable pipeline design codes require a re-qualification to ensure that the new premises for change in operation is properly assessed and confirmed acceptable with regards to pipeline safety, operability, and transport capacity. This paper addresses key issues with main focus on pipeline structural integrity.

1. Introduction

The potential for repurposing of existing onshore and offshore pipeline infrastructure for transporting CO2 has over the last decade been given increased attention. Both regarding cost and environmental footprint of building new dedicated pipelines, repurposing is considered a potential attractive option. The topic is addressed in several previous research studies, such as Rabindran et al [4].

In a recent techno-economical study performed by Carbon limits and DNV [5], a high-level screening of the European oil & gas pipeline network was performed to assess repurposing potential either for transporting CO2 or hydrogen gas. The study concludes on a significant potential for CO2, however also that the re-use potential will depend on several factors such as location, pipeline route, product composition, operating condition (dense or liquid phase), physical condition and other factors.

There are several key criteria that need to be considered carefully, and checks that need to be made, before approving a piece of onshore or offshore infrastructure for re-use. Implicitly the feasibility of repurposing of a specific pipeline needs to be confirmed and documented through a re-qualification process to confirm acceptable pipeline integrity as well as transport capacity. It is the intention of this paper to describe a methodology and to address key considerations specifically needed for re-qualifying oil & gas pipelines for transport of CO2 in line with guidance provided in DNV-RP-F104 [3].

2. The Value of Industry Standards & Guidelines

Industry standards, recommended practices and guidelines provide requirements, specifications, guidelines, and characteristics that can be used consistently to ensure that materials, products, processes, and services are fit for their purpose. Further, they provide guidance for the safe management of pipeline infrastructure - both for new design and re-use. Ultimately, they reflect industry experience and are often results of joint industry projects which establishes trust and confidence between stakeholders, authorities, and society. For pipeline transport of CO2, there are existing design codes that provides design criteria and guidance specifically for CO2 transport such as e.g. ASME B31.4 [6], DNV-RP-F104 [3] and ISO 27913 [7]. Figure 1 provides a high-level overview of existing codes across the CCS value chain within the ISO and DNV regime.

3. Key Considerations of Repurposing Pipelines for CO2 Transport

In the context of carbon capture, the CO2 may come from various sources and be captured by different techniques leading to variation in product-composition. Within the industry, there are specifications stating minimum 95% CO2 in the composition, where the remaining 5% is typically represented by hydrocarbons, nitrogen and other non-condensable, and with traces of sulfur, oxygen, glycols, and water [8]. The CCS industry is currently requiring a conservative composition close to 99% CO2, driven by limitations on acceptable impurities across the value chain from capture to storage or utilization. It is foreseen that this strict composition will be challenged in the future, hence this should be accounted for when considering repurposing of pipelines for CO2 transport. Further, industry experience shows that the corrosion rates, and possibly the impact on fractur control evaluations, are strongly affected by the type of impurities, combination of impurities and concentration of impurities [9].

The first challenge relates to risk of internal corrosion for C-Mn steel due to the high corrosion rates caused by CO2, hence the requirement to avoid free water across the pipeline system and foreseeable operating conditions. Corrosion risk assessment also needs to consider the additional effects of other impurity elements as e.g O2 and H2S in the composition.

The second main challenge is related to what extent the pipe could have sufficient toughness to arrest a running ductile fracture when operated in dense phase, which is also affected by the composition of the CO2 and the material properties of the pipeline. There is now an increasing body of evidence regarding the more challenging situations with respect to running ductile fracture in dense phase CO2 pipelines. It has become clear that the original Battelle Two Curve Method is non-conservative when applied to dense phase CO2 pipelines [10]. Recent large-scale tests point to potential requirements for high toughness,

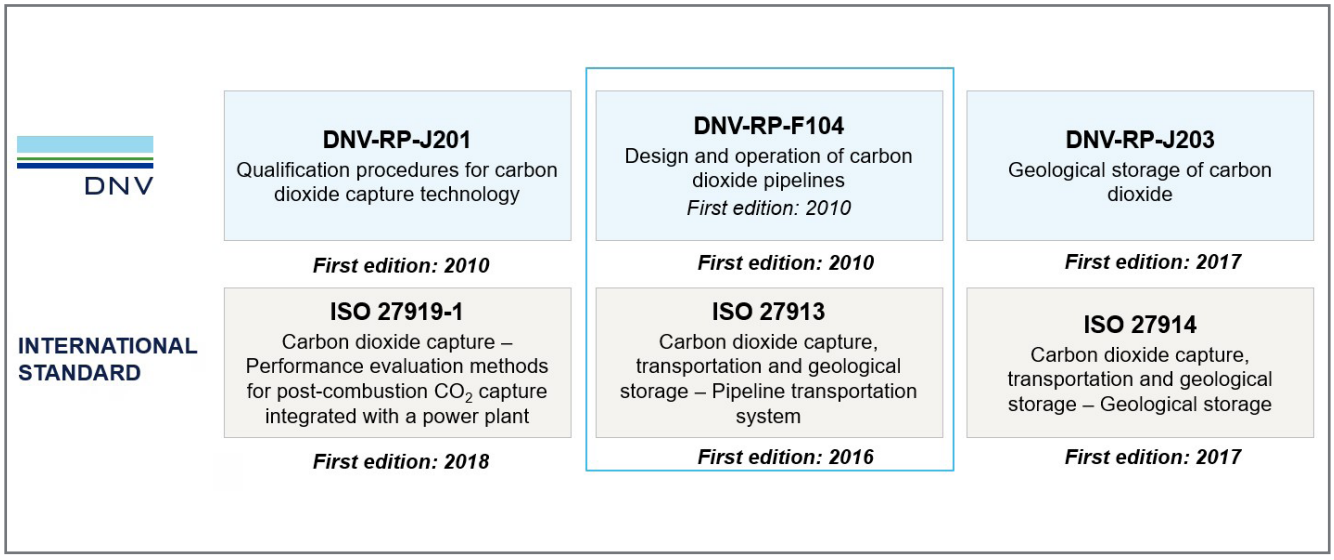

Figure 1: Overview of existing DNV and ISO codes related to CCS

with CVN energy above 300 J in some cases, to arrest running ductile fracture (see [11] for a summary). Such high CVN energy values could be challenging to document for older CMn-pipelines and could point to the need for considering alternative solutions, e.g. the use of crack arrestors as commonly used for onshore CO2 pipelines. For offshore pipelines, retrofitting crack arrestors may however be challenging and costly.

There has also been raised a concern as to whether smaller leaks in CO2 pipeline systems could lead to more severe cooling, which again could increase the risk of brittle fracture. The importance of this issue is, however, not fully understood [12].

From a more general perspective there are also potential challenges that needs to be handled related to change of flow direction, not only related to one-way equipment but also due to the change of pressure and temperature profiles with regards to pipeline load conditions.

Further, interpretation of existing regulations and potential change of location class (or safety zones) also needs to be evaluated as part of the re-qualification process.

4. How to safely repurpose a Pipeline System for CO2 Transport

4.1 General

DNV-RP-F116 [13] provides recommendations on how to manage integrity of submarine pipeline systems for the intended service life (Figure 2). Pipelines transporting CO2 are not specifically addressed in DNV-RP-F116 but gives references to DNV RP-F104 covering pipelines for CO2 transport specifically. Generally, when a pipeline is considered used for a purpose other than it was originally intended, or by not fulfilling the original design criteria, a need for re-qualification is triggered.

4.2 An outline of the various steps in a re-qualification process

As a general rule, the re-qualification shall comply with the same requirements regarding safety and operation as for a pipeline designed specifically for transportation of CO2. The re-qualification process is recognized through the process given in Figure 3 and briefly described through the steps 1-9 below.

Step 1 - Initiation: The original design basis and any later modifications, operation parameters, operational history and battery limits extracted from the DFI résumés needs to be established. Key elements within the battery limits, materials selection as well as the pressure rating of the pipeline system needs to be identified. This is key information that needs to be screened as part of the re-assessment part (step 7), i.e. forms the basis for the gap analysis for requirements for CO2 operation. A risk assessment should be carried out and a project risk register developed which identifies the risks associated with changing the type of product to be transported from existing to in dense phase or gas phase. The base requirements for the re-qualified pipeline should be established. This includes aspects such as 1) capacity (how much CO2 to be transported),

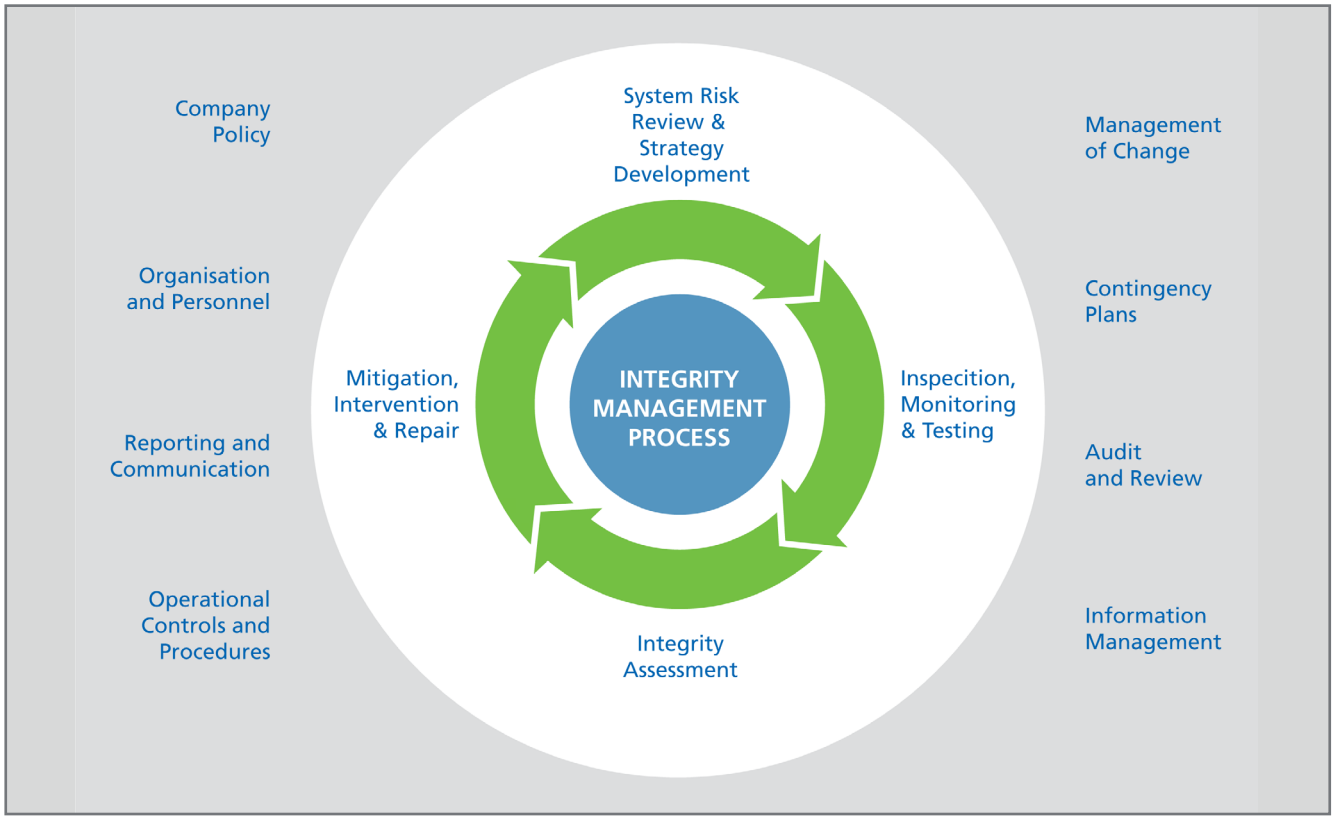

Figure 2: Integrity management system

2) delivery pressure, 3) CO2 state and composition to be transported which will influence the later integrity and safety studies.

Step 2 – Integrity assessment: As a starting point, the current integrity of the pipeline system shall be addressed through assessment of the technical condition prior to changing to CO2 operation. Historical information of how the system has been operated compared with the requirements for operation should be assessed and documented. Identification of material selections as well as the pressure rating and the current condition of the pipeline system are key information that shall be screened as part of the integrity assessment.

Step 3 – Hydraulic analysis and flow assurance: Changing existing product to CO2 may have implications for the pipeline transport capacity and load conditions. A flow analysis should be performed to identify feasibility with regards to transport capacity and corresponding pressure and temperature distribution along the route. A high-level hydraulic analysis, comparing the key operational parameters when operating with current product and CO2 respectively shall be performed as input to the pipeline load conditions.

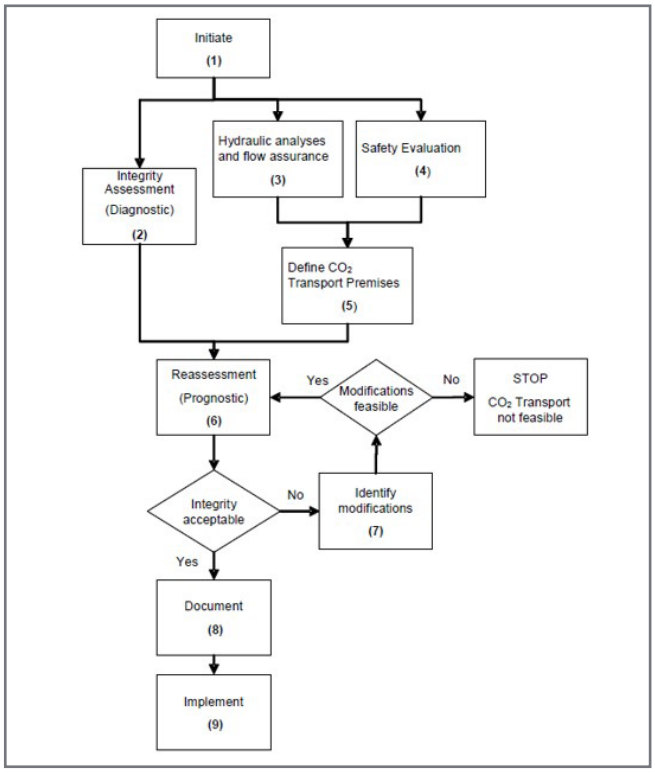

Figure 3: Re-qualification process for pipeline system change into CO2 transport [3]

A representative set of operating conditions shall be covered to establish pressure (steady state and transient

operation) and temperature profiles. Requirement for modifications of the pipeline system should be identified and evaluated.

Step 4 – Safety Evaluations: Safety evaluations should be performed, addressing the implications of a change of product. The system as it is designed should be evaluated toward the specific safety requirement for CO2 pipelines. Need for modifications of the pipeline system should be identified and evaluated, e.g. additional block valves, upgrade of leak detection system etc. The suitability of components / replacements of valves and gaskets not suitable for CO2 should also be evaluated. Attention shall be given to accidental release scenarios, and the effects on consequence radius due to the change of product.

Step 5 – Define CO2 transport premises: Premises for CO2 transport should be defined incorporating the results from the hydraulic analysis (3) as well as safety evaluation (4). These aspects will define functional as well as system requirements that may deviate from the original design conditions. Requirements to the system should be identified and included as part of a complete premise for the re-qualification. This includes stating design / incidental pressure, receiving pressure etc.

Step 6 – Reassessment: Based on the input from the integrity assessment (2) and the CO2 transport premises (5), the integrity should be evaluated for the new premises. Parts of the system that is identified not to be compliant with the integrity requirements will require design modifications and reiteration on the re-assessment. In some cases, the required modifications are not feasible e.g. from a cost-benefit standpoint, leading to termination of the re-qualification process.

Assessment of additional Failure Mechanisms: Additional failure mechanisms relating to the changed operational conditions shall be identified, considered, and evaluated. Key areas to be addresses are typically:

- Compliance with existing material properties
- Load conditions: Re-assessment of the pipeline system, specifically addressing the implication of new premises on pipeline load conditions. The assessment shall be performed comparing the requirement in the original design code and with specific requirements for the system in question.
- The change in operational conditions

Risk register: The risk register established in (1) shall be updated and any risks associated with the pipeline including upstream and downstream battery limits identified. The risk assessment shall confirm that these changes are appropriately addressed in relevant management and replacement plans for the pipeline.

Comparison of original and new design standards: A gap-analysis to identify gaps between the original design standard and applicable current design requirements and CO2 specific guidelines or recommended practices should be performed. Re-assessment of the pipeline system shall be performed, specifically addressing the implication of new premises on pipeline load conditions.

Step 7 – Modifications: Modification alternatives should be evaluated with respect to feasibility, safety, and integrity. A re-assessment of the modification alternative will be performed through documenting the integrity status. This activity shall cover identification and description of possible mitigations or modifications to ensure safe operation with CO2, considering acceptable levels of impurities and operating envelope, other modifications/mitigations for improving load condition for the pipeline, material testing to document (original) material properties when information is lacking etc.

Step 8 – Document: Documentation of the re-qualification process as well as update of system documentation, drawing, equipment lists, and operating procedures is required to ensure that the re-purposed pipeline can be safely and effectively operated.

Step 9 – Implement: Implementation of changes to the system should be performed prior to transition of the system into the new operational mode for CO2.

5. Hydraulic Analysis and Flow Assurance (Step 3)

For existing pipelines purposely built for transporting CO2, the pipeline design and operating envelope is in

most cases adapted to transport the product in liquid (dense) phase. This is due to the favorable combination of high product density and low viscosity for the liquid phase, allowing for optimization of both installation (i.e. reduced pipeline diameter) and operational cost. Figure 4 shows a typical phase envelope for pure CO2 and for a 'synthetic' composition containing 97%CO2 and 3%N2. Operation in liquid phase requires minimum pipeline pressure rating in the range of 80 to 100 bar, depending on stream composition and range in operating temperature, ref. Figure 4. For offshore pipelines, the pressure rating will in many cases be higher than 100 bar, i.e. sufficient to enable operation in liquid (dense) phase.

Offshore gas pipelines typically have a design pressure in the range of 150 bar. It should be acknowledged that in most cases it is not possible to re-qualify a pipeline to higher pressure rating, considering that pipelines are normally optimized on design loads, including pressure containment. Hence, with regards to determining transport capacity, the pipeline pressure rating should first be identified to conclude feasibility of operation in liquid phase, or whether gas phase at lower pressures is the only viable option.

For onshore oil & gas pipelines, pressure rating is typically less than 80 bar and the pipeline would normally be operated in close balance with ambient temperature, either exposed above ground or buried. Pipelines with pressure rating less than 80 bar may still be feasible for transporting CO2 in gas phase, however the limitation in upper operating pressure for the avoidance of two-phase flow condition needs to be acknowledged. Conservatively the maximum operating pressure for gas phase transport may be determined by the saturation pressure at the minimum operating temperature of the pipeline, i.e. the pressure at which a liquid phase will start to drop-out (condensation). Minimum operating temperature will typically be governed by a combination of inlet temperature and thermo-hydraulic response of the pipeline from inlet to outlet, including the effects of pipeline insulation and variations in ambient temperature.

To confirm acceptable margin to two-phase flow, hydraulic simulations should be performed with appropriate tools to determine relevant range in pressure

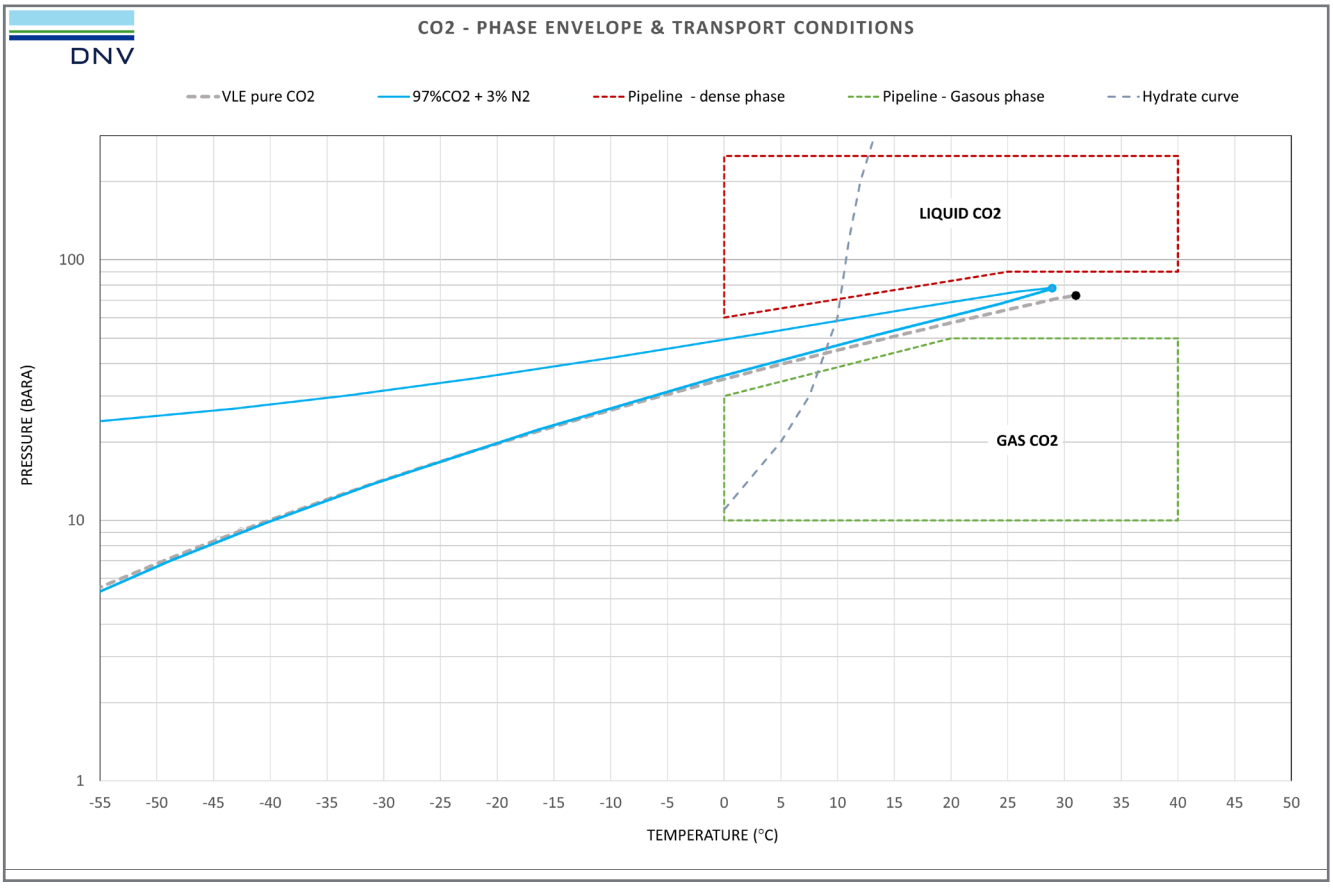

Figure 4: Phase envelope for pure CO2 and composition of 97%CO2+3%N2; for illustration; typical operating envelope for dense and gas operation indicated.

and temperature profile along the pipeline route for the actual product composition. As an example, if the minimum ambient soil temperature for a buried pipeline is 10°C, the maximum operating pressure in gas phase needs to be limited to approximately 45 bar, depending on product composition. Combined with the pipeline size, length and minimum required arrival pressure, this limitation will have direct implications for the pipeline transport capacity. Regarding flow assurance, one key concern is to ensure sufficient control on product water content to prevent drop-out of free water and subsequent corrosion risk. In this context it should be acknowledged that water solubility varies significantly between liquid and gas phase and may also be affected by the presence of other impurities in the product [13]. Also the potential for free water drop-out in upset conditions, including off-spec product should needs attention.

In addition to the assessment of transport capacity, temperature and pressure profiles should be established from thermo-hydraulic simulations for a representative range of operating conditions to provide input to the new pipeline load conditions. The simulation cases should typically include design cases, normal operation, turn-down case(s), line-packing, shut-down and re-start. Pipeline depressurization (rare event) should also be simulated to document that the pipeline can be safely depressurized within reasonable time and within the specified design conditions such as minimum design temperature.

Repurposing existing oil & gas pipelines for transporting CO2 will in many cases require reversing the flow direction which will have implications for pressure and temperature profiles. Any 'one-way' equipment or functions needs to be identified and assessed. Booster or pressure reductions stations may need to be bypassed or reconfigured and non-return valves etc. may need to be removed or locked open.

6. Safety Evaluations (Step 4)

Safe operation of CO2 pipelines has been demonstrated through a number of pipeline projects related to enhanced oil recovery (EOR) and CCS [1]. There is currently no evidence to support that the failure frequencies for CO2 pipelines should be higher than for comparable oil & gas pipelines [15].

However, it should be acknowledged that these pipelines are purpose built for transporting CO2, and that special measures both regarding design and operation are implemented to manage integrity and mitigate major accident scenarios. It should also be acknowledged that most of the existing CO2 pipelines run through remote areas with limited interference by and potential for exposing 3rd party. To lean on the current experience from onshore CO2 pipelines, it therefore needs to be evaluated whether the relevant safeguards can be achieved and is also sufficient for existing oil & gas pipelines repurposed for CO2 in more highly populated areas, alternatively whether this can be mitigated by other safeguards.

The safety evaluations for operation with CO2 should be performed on the back of the hydraulic analysis to ensure correct assessment of the hazard potential, both considering normal planned operations and accidental release scenarios. Due to the significant difference in pipeline inventory between CO2 pipelines operated in dense and gas phase the corresponding differences in consequence scenarios for pipeline failures should be acknowledged regarding release rates and duration.

7. Re-Assment (Step 6)

7.1 General

This section outlines some key material aspects and aspects in design of CO2 pipelines.

7.2 Key material aspects for pipeline systems

Steel material: As outlined in Section 3, there are materials aspects related to CO2 transport that needs special considerations when assessing pipelines for such use. These are related to potentially increased degradation of the steel pipeline due to:

- Internal corrosion in presence of water
- Embrittlement in case of CO2 compositions with certain impurities, e.g. H2S
- Embrittlement in case of low steel temperatures in relation to small leaks

There are also scenarios where the CO2 could lead to higher loading of the pipeline, and thus increased requirements to material properties, which especially is

related to toughness requirements to arrest running fracture in CO_2 pipelines.

Non-metallic materials: Dense phase CO_2 behaves as solvent to certain non-metallic materials such as elastomer seals and gaskets. With respect to polymeric materials elastomers, both swelling and explosive decompression damage needs to be considered. Swelling of the elastomers is attributed to the solubility/diffusion of the CO_2 into the bulk material. Explosive decompression may occur when system pressure is rapidly decreased and the gases that have permeated into the elastomers expand. Candidate materials also needs to be qualified for the potential low temperature conditions that may occur during e.g. the pipeline depressurization scenario.

Natural gas pipelines with internal flow coatings may run a risk of coating detachment from the base pipe material in a potential low temperature condition associated with rapid pipeline de-pressurization.

7.3 Design aspects

The same limit states as for other pipelines applies for pipelines transporting CO_2. However, due to different characteristics of the CO_2 compared to e.g. natural gas, a pipeline designed to transport CO_2 including required intervention may not be identical to a pipeline transporting natural gas, even for cases when the design pressure and diameter are identical.

Internal corrosion: If free water is present in the CO_2 flow, this could lead to significant corrosion rates and selecting a corrosion allowance to mitigate this will not be sufficient. Therefore, both strict control of the containments in the flow and drying of the flow is essential for transport of CO_2 to prevent internal corrosion. Corrosion resistance alloys may be selected for new pipelines but comes with an increased cost, and this is obviously not an option for repurpose of existing carbon steel pipelines.

Fluid category and safety zones: The recent revisions of ISO 13623 [16] and DNV-ST-F101 [2] have moved CO_2 into a more severe fluid category compared to earlier revisions of the codes. The fluid category for CO_2 is now the same as for natural gas, and hence the design factor for pressure containment for a pipeline conveying CO_2 and natural gas is the same, provided that the population density (number of people) within the consequence zone is the same. Depending on the volumes in the pipelines, the consequence zones for CO_2 pipelines may be larger as the CO_2 is spreading along ground and not up in the air. If the consequence zone is increased this may give a larger/stricter location class, which in turn will result in a reduced pressure containment design factor which again will result in a reduced design pressure.

Running ductile fracture: Full scale fracture arrest tests have revealed that pipelines conveying CO_2 are more vulnerable to running ductile fractures than natural gas pipelines, i.e. the design approaches applied for natural gas pipelines are non-conservative for CO_2 pipelines. Hence, a pipeline transporting CO_2 is expected to require a higher fracture toughness and/or thicker wall thickness or having restrictions with respect to CO_2 composition and temperature to control the saturation pressure which governs the driving force for running ductile fractures. For re-qualification it is not possible to increase fracture toughness or wall thickness, so in case insufficient characteristics an alternative is to control the CO_2 composition and temperature to arrive at acceptable saturation pressure, or to mitigate fracture arrest by e.g. fracture arrestors where required and possible.

Brittle fracture: If there is a small leak in a CO_2 pipeline in combination with significant stresses in the area, initiation of brittle fracture is a possible scenario. A detailed analysis of this issue is currently challenging. Beneficial information would be if existing materials certificates point to good low temperature toughness (e.g. low CVN energy transition temperature). Further, effort to minimize the risk of leaks in critical regions would also be of benefit to reduce the likelihood of such events.

Reversed flow direction: Pipelines being re-qualified for CO_2 transport (in case of storage) may often change inlet to outlet (and vice versa). The original design of the pipeline has typically accounted for expansion forces due to pressure and in particular temperature, to allow safe operation of the pipeline. Since the temperature loading is most pronounced at the inlet end of the pipeline, typically little or no considerations have been placed to the outlet end of the pipeline due to limited expansion forces. However, when inlet and outlet ends are changed, expansion forces may be relevant at

the (new) inlet end. This will require that the expansion potential and forces are evaluated and may lead to additional intervention to accommodate the increased expansion forces, by e.g. increased burial to avoid upheaval buckling or by allowing the pipeline to expand in a controlled manner.

Effects of weight and mass of fluid: The density of the CO2 in dense phase could be in the range of 10 times higher than the density of the natural gas, while the density of CO2 in gas phase is more similar to natural gas. Hence, if CO2 is transported in gas phase the weight and mass of the pipeline may not change significantly, however, for dense phase CO2 the weight may increase significantly. If the weight of the pipeline increases, this may decrease the acceptable free span lengths as the bending of the pipeline increases on supported shoulders, and additional mitigation may be required. Further, an increased mass will change the natural frequencies of e.g. free spans and hence the acceptable free span length may be shorter due to changes in the fatigue/fracture loading response, and additional mitigation may be required. The dynamic loads from e.g. waves and current may also change due to changes in weight and mass. Changes in weight will also influence on-bottom stability.

Third party loads: Loads from third party are generally not changed when changing from natural gas to CO2 transport, however, if weight and mass of the pipeline is changed this may change the response of the pipeline.

8. Summary and Conclusion

This paper has discussed a general approach for re-qualification of pipelines for CO2 transport. There are several key criteria that need to be considered carefully, and checks that need to be made, before approving a piece of onshore or offshore infrastructure for re-use. Implicitly the feasibility of repurposing of a specific pipeline needs to be confirmed and documented through a re-qualification process to ensure acceptable integrity, safety as well as transport capacity. General codes and recommended practices that lay out requirements and guidelines for design an operation of CO2 pipelines are already available and can be used as basis for re-qualification of CO2 pipelines. It is foreseen that these standards will evolve with the CCS industry to incorporate latest research. In this paper, the various steps in the re-qualification process in DNV-RP-F104 has been outlined.

There are however aspects that could benefit from further research, e.g. formulation of requirements for running ductile fracture and eventual environmental embrittlement. Impurities in captured CO2 affect critical pressure, critical temperature, and phase behavior, which may affect pipeline materials and design parameters. Other challenges related to repurposing of pipelines may be general lack of design and construction documentation for older pipelines. Also, repurposing of pipelines for CO2 transport may be challenged by local rules and regulations, and interpretation of such. Thus, re-qualification of pipelines, especially for CO2 transport in dense phase, is therefore not considered trivial and requires a careful evaluation but is nevertheless considered as fully possible in many cases.

'The feasibility of repurposing of a specific pipeline needs to be confirmed and documented through a re-qualification process to confirm acceptable pipeline integrity as well as transport capacity.'

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PE Pipelines – Improvement of productivity and safety using mobile VFT Welding Tracs

S. SCHWARZER > VIETZ

Abstract

Nowadays plastic pipelines form an integral part of modern infrastructure. The most common applications for butt-fused plastic pipelines are water and natural gas distribution networks. Inventions of new materials, production and installation methods for extruded pipes enables new applications and dimensions in a growing range of needs.

Climate changes causes challenges for urban and non-urban regions around the globe. Periods of heat require irrigation for farms as well as water to fight against wildfires. Environmental energy from wind farms, solar farms and hydroelectric power plants will reduce the carbon dioxide output level for energy production, however the high voltage grid needs to be updated to avoid shutdowns. New power grids like "SuedLink" in Germany, where hundreds of kilometres of protection pipes for cables will be required, are the markets for the future.

It is now possible to optimise the installation method for fuseable plastic pipes to make long distances more reliable and cost effective.

VFT welding Tracs are suitable for safe and economic plastic pipeline installation. They are self contained and self propelled all terrain machine carriers for butt-welding machines. In combination with state of the art welding equipment and the onboard generator a full automatic welding process is possible. Data logging systems enable a 100% report for all joints. The automatic self load and clamping system for the pipe increases the health and safety standards for the operators. The accident risk is much lower than with pipe handling with a crane or excavator. There is no need for lifting equipment during the welding process. This saves labour expenses and equipment costs.

1. Application fields for Polyethylene (PE) and Polypropylene (PP) pipes

1.1 Public services and energy:

- Oil and gas
- Water and stormwater
- Sewage
- Desalination of seawater
- Protection pipes for telecommunications
- Protection pipes for power grids
- Hydroelectric power

1.2 Construction and farming:

- Drainage and groundwater lowering
- Pipeline rehabilitation
- Trenchless technologies
- Irrigation and firefighting water

1.3 Mining:

- Coal bed dewatering
- Methane extraction
- Heap leaching
- Water processing
- Slurry processing
- Water transportation

2. Benefits using VFT Fusion Tracs

VFT Welding Tracs are self contained and self propelled all terrain machine carrier for butt-welding machines. In combination with state of art welding equipment and the onboard generator a full outomatic welding process is possible. Data logging systems enable a 100% report for all joints.

The automatic selfload and clamping system for the pipe increases the health and safety standards for the operators. The accident risk is much lower as with pipe handling with a crane or excavator. There is no need for lifting equipment during the fusioning process. This safes labor expenses and equipment costs.

The large 360° panorama view cabin protects the operators against all elements i.e. rain and snow, sun and UV radiation and heat and coldness, dust and dirt and wind and cold. The climatic controlled cabine (heater and air-condition) guarantees a constant temparature for the operator as well a high quality joint according to the international welding standarts for PE and PP pipes.

A special fusioning working yard is redundant. The setup of fusioning equipment, weather protection tent or container, generator, pipe handling equipment

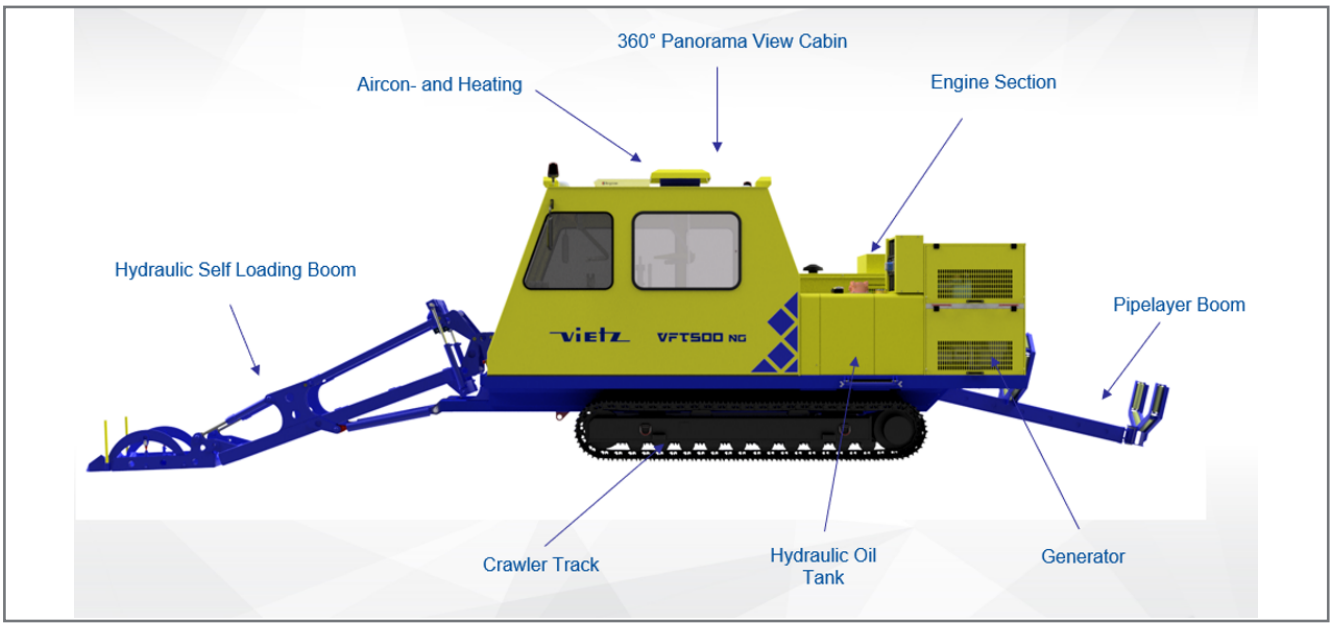

Figure 1: VFT 500 (180-500 mm) System setup

Figure 2: VFT 500 (180-500 mm) on jobsite in Australia

(excavator, crane) for a limited range of distance is not efficient in comparasion to the all-in-one VFT solution moving forward with the installation process. Setup times are minimized.

A one man operation and the optimized fusioning process using the VFT welding tractors enables more productivity. Savings against conventional process are 30-50% depending on pipe size, wall thickness and local situations. As an option "optimized cooling equipment" can increase the savings up to 50-70% based on reduced cooling times. Track undercarriage with optimized cross-country mobility, reduced compression of ground and road-liner rubber pads as option for asphalt/paved surfaces.

3. Range of application VFT Tracs

Model	Pipe sizes (metric)	Pipe sizes (imperial)
VFT 300*	110-355 mm	4-14“
VFT 500	180-500 mm	7-20“
VFT 900	340-900 mm	13-35“
VFT 1600*	500-1600 mm	20-65“
* R&D study		

Table 1: Available VFT Trac sizes

4. Conclusion

Plastic pipes i.e. Polyethylene (PE) and Polypropylene (PP) pipes are and will be a significant part of all applications related to fluid transports. Underground or above ground, long service life or short term solution does´t matter, the material caracteristics of the material enables all facets in all applications.

In addition to the common applications farming will requires irrigation solutions, the mining business needs effective fluid solutions and the transformation of our power grids to environmental energy a lot of new high power grids within protection pipes.

Figure 3: VFT 900 (340-900 mm) 800 mm trials before delivery to the client

Within a growing market the VFT Fusion Tracs enable a efficient, more save and reproducibility of all jobs. The pipe range from 110 to 1600 mm (4-56") guarantees a full range in all applivcations. The health and safety aspects of the operators are optimized and part of the VFT Trac concept.

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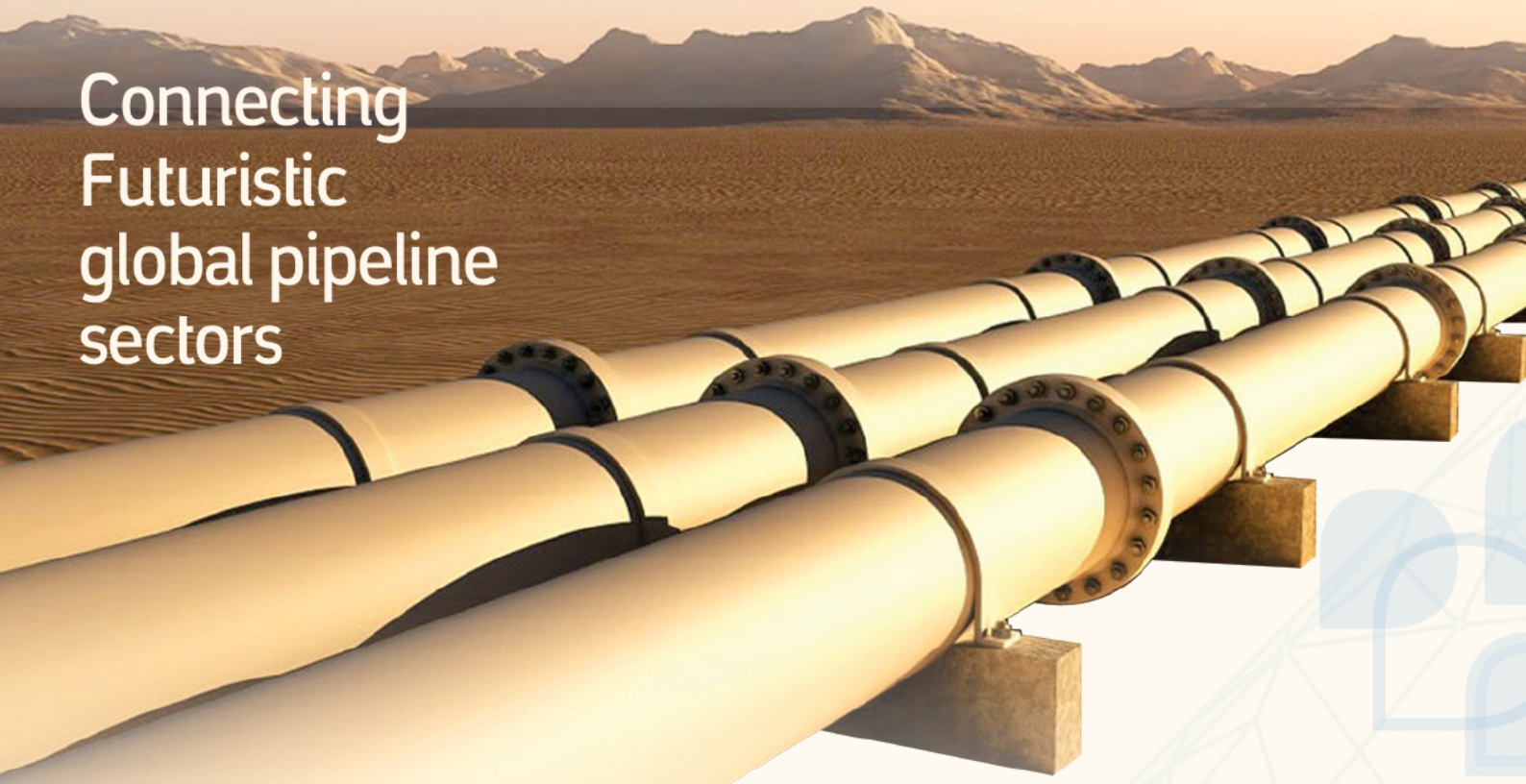

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Construction & Coating

Q1) What is the key to success for coating joints in the field ?

Answer: If weld seams or joints are to be safely protected in the field, the processing of the coating material is often subject to very difficult environmental conditions. Whether the influence is temperature, humidity, wind - or even construction site conditions: they can all have a significant impact on the processing and the result, and thus the quality of the coating.

As the international standard ISO 21809-3 defines 11 different families of coating systems, which are themselves subdivided into many sub-categories, the choice of the right coating is very wide and makes the selection of the most successful coating material a challenging task. This task becomes even more difficult when one considers that ISO 21809-3 distinguishes the different products according to their material composition and not according to load classes or resistance in the field.

As the coating of the joints is applied in the field where application conditions are difficult to control and often unpredictable, coating materials requesting the least restrictive application procedure are generally the ones who succeed in the long term.

However, limiting yourself to the conditions during the application of the products would not meet the requirements of the very long service life of pipelines. These can vary greatly depending on soil conditions, chemical, mechanical and temperature loads.

Therefore, the key to success in selecting the right coating for the joints is to use a product that is very easy to process, involves only as few steps as possible, can be corrected during application and withstands the real stresses in the field with the most appropriate corrosion prevention performance.

Q2) What kind of technologies are available to check the quality of buried pipeline coatings?

Answer: First of all, one must distinguish between the quality control of the applied coating in the field when having free access to the coating, e.g. prior backfilling the pipe trench or after excavation of the pipe, and the check during the operation of the pipe in the buried condition.

When checking the quality of the coating onsite having free access to the coating, e.g. in the trench, there a lot of non-destructive as well as destructive methods available, that are listed in the respective standards of the different coatings, e.g. mill coatings or field applied coatings. The most important methods in the field are the following

Non-destructive tests:
- Visual inspection
- Thickness measurement
- Electrical holiday detection
- Electrolytic holiday detection

Destructive test:
- Coating adhesion test
- Peel strength testing
- Shore-D measurement for material hardness
- Chemical analysis

According to our knowledge, a direct check of the quality of the coating in the buried condition is not possible up to now. However, there are methods available to get an indirect impression of the quality of the existing coating, i.e. either detecting a reduction of the pipe wall thickness or detecting coating defects.

These methods include internal inspection techniques such as in line inspection tools, or above-ground non-intrusive techniques such as direct current voltage

gradient surveys (DCVG), alternating current voltage surveys (ACVG) and close-interval potential surveys.

partial pressure. This can be a complicated asset specific analysis, but we are finding that some systems may be compatible nearly as-is, with minimal modifications, while some may require modification or upgrading of certain components, whereas other systems may not be feasibly converted without significant upgrades and costs associated.

Q3) How do pipeline coatings interfere with cathodic protection systems ?

Answer: A functioning and coordinated active and passive corrosion protection are decisive for the lasting integrity and failure-free functionality of a newly installed steel pipeline as well as for the achievement of its intended and planned service life.

Passive corrosion protection includes all measures which achieve a shielding/protective effect against corrosive media. This can be attained e.g. by an appropriate selection of anti-corrosion coating as well as design features. The function of a coating is to separate the metal surface to be protected from the surrounding corrosive medium (electrolyte) with respect of mass as well as charge transfer. Such the formation of corrosion cells is inhibited.

In the case of cathodically protected pipelines any coating is the First Line of Defence.

Cathodic Protection (CP) will act as a Second Line of Defence in the event a defect occurs in the corrosion prevention coating.

For technical and economic reasons pipelines are usually protected by a combination of active and passive corrosions protection. This combination has proved its value for many decades.

It is generally accepted that the effect of cathodic protection is based on the activation polarization and the concentration polarization of the steel surface resulting in an increase of the pH at the interface between steel and soil. This increase in pH-value may affect the adhesion of the corrosion prevention coating in the immediate vicinity of the defect. The criterion of cathodic disbondment (CD) is therefore part of all serious standards for the corrosion protection material of steel pipelines laid in soil and water in conjunction with CP.

Interestingly, the effects of the alkaline environment on layered corrosion protection materials - e.g. polymeric tapes or shrinkable sleeves- have not been the subject of normative considerations yet, although possible damage to the coating material by alkali – here layer to layer adhesion - may pose a significant risk to the pipeline. The same applies for the often-neglected parameter of the shape stability. As long as the delaminated coating rests tightly on the steel surface in the form of a tube (shape stability), no corrosion problems occur.

Corrosion can only occur under delaminated coating if a relevant volume is able to push in between the coating and the pipe surface. In other words, if the coating is not dimensional stable or has lost the shape stability, a relevant volume is able to push in between the coating and the pipe surface. As a result, galvanic elements are formed in combination with heterogenic aeration (oxygen concentration gradients) resulting in an enhanced local corrosive attack, e.g. crevice corrosion, despite of the low oxygen permeation through the coating. In the case of a very low shape stability one even could expect, that a very large and continuous volume between the coating and the pipe surface is formed- in a worst case leading to a flow of oxygen containing water between the coating and the pipe surface.

If the coating parameters layer to layer adhesion and shape stability degrade due to a high pH, i.e. pH > 10, the coating loses its functionality. This is independent of the origin of the high pH, e.g. effect of cathodic protection or the use of fluidized soil.

Q4) Do you believe that organic coatings (epoxy etc.) applied inside the pipe would prevent or slow the hydrogen ingress into the steel pipeline ?

Answer: The diffusion processes of hydrogen differ elementarily for organic coatings and for steel. Therefore, the comparison of the diffusion coefficients of hydrogen for these materials is not sufficient to enable a reliable answer to the question.

In the case of organic coatings hydrogen diffuses molecular through the porous material, whereas in the case of steel individual hydrogen atoms diffuse through the metal lattice. This implies in a pre-step the dissociative adsorption of hydrogen leading to adsorbed hydrogen atoms. For this adsorption process free iron atoms are needed at the surface.

On the one hand these iron atoms at the surface can be partially covered by the epoxy coating, whereas in the absence of an epoxy coating iron oxide layers are formed and therefore the number of free, reactive iron atoms is also limited. To what extent an epoxy coating influences the rate of adsorbed hydrogen atoms is still the subject of current research and not clarified.

Finally, we have to state, that due to the described mechanisms a simple comparison of the diffusion coefficients of hydrogen for the different materials is not helpful, in fact it may be misleading.

Q5) Why are there 2-ply and a 3-ply plastic tapes and what is their difference?

Answer: Corrosion prevention tapes and tape systems, made of a combination of i.e. Polyethylene (PE) and Butyl rubber have been on the market for over half a century and have established themselves as the leading quality solution. Out of a wide range of possible combinations, the usual distinctions are between 2-ply and 3-ply tapes.

3-ply tapes are used as corrosion prevention tapes and are wrapped around the pipe as the primary protective layer. Those 3-ply tapes are made of three layers: from the top to the bottom: "compound" – "carrier film" – "compound". The top and bottom layers can be symmetric (same thickness) or asymmetric (very thin layer on the top and thicker layer on the bottom). Due to strong amalgamation of the compounds (butyl rubber) at the overlap area, 3-ply tapes form a homogenous sleeve type coating with no path for water and oxygen and with superior adhesion between tapes layers. A thick compound layer at the bottom for instance ensures best coverage: cavities and picks on the steel surface are protected.

2-ply tapes made of PE/butyl rubber should only be used as additional mechanical protection on top of 3-ply tapes. 2-ply tapes consist of two layers of material: the top laser is called "carrier film" and the bottom layer is called "compound". If the carrier film is made of Polyethylene and the compound is made of butyl rubber, the 2-ply tape wrapped onto a 3-ply tape perfectly bonds to the outer compound of the 3-ply tape. In combination, this tape system provides very good corrosion prevention and mechanical resistance.

2-ply tapes can also be made of Polyvinyl chloride (PVC) as carrier film and bitumen. However, no bitumen is used to manufacture 3-ply tapes.

When using 2-ply tapes as only solution for corrosion prevention, the risk of spiral corrosion occurs as there is no amalgamation between the carrier film and the compound.

Q6) Are there different ways in producing corrosion prevention tapes? Does it have an influence on quality? How can you test the difference?

Answer: Tapes are made of different materials that are interlinked by lamination or coextrusion during the production process.

All lamination technologies have in common that at least one layer has already cooled before it its covered by another layer: a material is applied to a cold, solidified carrier film, which adheres to the carrier material like gluing. The different layers create a bond but are still independent from each other.

In coextrusion technology, different materials are present in molten form during the joining and bonding process. The different melt streams flow into a multi-layer common die through different channels. Along the flow path, the individual melt flows – and therefore the macromolecules of the molten materials – are increasingly combined with each other and mixed to the extent that they penetrate into each other generating at the end of the process one single material line that consists of several layers.

The bond established between the materials is so strong that it can be compared to welding. The carrier and the coating material form one indivisible unit.

As a result, the tape cannot be separated into its individual functional layers, as it might be the case with laminated tapes. Compared with laminated tapes, coextruded tapes show higher layer to layer adhesion and stronger lap shear resistance which ensure outstanding sustainability in the long term.

As a simple test to distinguish between a laminated tape and a coextruded tape we recommend to immerse a piece of tape into petrol for a minimum of 2 hours.

If the residual adhesive is easily removed and the carrier film is smooth or glossy, you can assume a lamination process. If the residual adhesive can only be removed with strong mechanical devices, you can assume a coextrusion process.

Q7) How does pipeline surface preparation and coatings application determine the success of coating?

Answer: This question is related to field-applied coatings where application conditions are more difficult to ensure and verify in comparison to factory applied coatings.

Surface preparation includes cleanliness (from dust, grease, etc.), surface profile (anchor pattern), and moisture (rain, fog or condensation). Cleanliness and moisture affect adhesion, whilst the surface profile affects cathodic disbondment.

Coatings application conditions depend on the coating type:

- Heat shrinkable sleeves need enough heat, including preheat and post-heat, as well as avoiding trapped air under the sleeve.
- Liquid coatings need the correct mixing ratio, proper application thickness, and enough curing between the different passes.
- Tapes need enough tension and constant overlap, both of which are generally easily secured by a manual or motorized wrapping machine.

The vast majority of coating failures that occur on-site are not caused by intrinsic failure of material properties, but by improper surface preparation and/or inappropriate application of the coating. Therefore, the human impact on coating failures must be minimized by developing easy-to-apply and failure tolerant coatings, ideally with only one work step.

A coating system which can be corrected or adjusted during application (also with a machine) is most likely to be the most successful solution.

Q8) What is the recent, innovative advancements being made in the pipeline field applied coatings industry?

Answer: The challenges in the coating industry are constantly increasing with shorter project times, higher standard requirements and still complex application of some products. Besides the permanent protection of pipe sections and weld seams, speed, safety and efficiency are all essential requirements.

A very decisive aspect has been added in recent years: sustainability and environmental protection – also in the corrosion protection solutions used. A clear focus is placed on using as little material as possible and avoiding waste. Likewise, no substances or solvents that are hazardous to health should be used. If, in addition, the work steps for the applicator are reduced and no additional equipment (such as gas flame or UV lamps) must be used, this not only improves the working environment but also the protection of people.

Innovative developments based on high standards fulfillment of ISO 21809-3 and EN 12068, like a tape application without primer and just one wrap to secure corrosion and mechanical protections at the same time, are recently introduced to the market. This represents a milestone in the development of sustainable and safe corrosion protection solutions.

THE EXPERTS

Dr. Thomas Löffler, Head of the Competence Centre Corrosion Prevention, DENSO
Thomas Löffler holds diploma and Ph.D. in chemistry, specialization in electrochemistry. He has over 17 years' experience in chemical engineering, electrocatalysis and mainly in corrosion protection. He also worked at E.ON Ruhrgas (today OGE) and was responsible for the issues of passive corrosion protection. At DENSO Group Germany he is the head of the Competence Centre Corrosion Prevention. He is a member of several national and international working groups of DVGW, DIN, EN and ISO and author of various scientific publications.

Luc Perrad, International Sales Director, DENSO
Luc Perrad has a master's degree in civil engineering – specialization in Electronics & Mechanics. He has over 14 years' experience in sales and marketing of field applied pipeline coatings in Western Europe, Africa and the Middle East. His functional experience includes marketing, strategy appraisal, due diligence and business management in sales of cold applied polymeric tapes, liquid epoxy coatings, heat shrinkable sleeves, visco-elastic tapes and mesh backed tapes. He joined DENSO Group Germany in 2019 and took over the position of International Sales Director in March 2021. Luc Perrad is NACE Coating Inspector Level 2 since February 2014.

With each issue of the journal, the "Ask the Experts" section focuses on a new topic of particular relevance to the pipeline industry. People from the international pipeline community are invited to send in their questions which will afterwards be answered publicly by selected experts from the respective field.

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