Issue 4 / 2018

ptj

eJournal

Pipeline Technology Journal

OFFSHORE PIPELINES

www.pipeline-journal.net

ISSN 2196-4300


Advanced in Sealing.
DENSO
DENSOLEN®
Tapes and Systems
■ Reliable corrosion prevention and strong mechanical resistance
■ For extreme temperatures: -50 °C to +100 °C (-58 °F to +212 °F)
DENSOMAT®
Wrapping Devices
■ For fast and secure application
■ High flexibility for all diameters
made in Germany since 1922
www.denso.de

"Storms make *Pipelines* take deeper roots"

Steffen Paeper
Senior Offshore
Commissioning Engineer

What an outstandingly warm summer this had been. We hope you could enjoy the sun and recharge your energy levels. Maybe some of you spent time on the water, including passing wind turbines and crossing offshore pipelines. However, despite the warmth, parts of Europe have suffered from severe weather, like dryness, thunderstorms, and flooding. It has been forecasted that these atmospheric disturbances may happen more frequently.

- Is our energy infrastructure, like pipelines and wind turbines prepared for changing hazardous environments?
- Can these energy carriers coexist, safely, efficiently, and independently?
- What technologies are available for tapping new energy resources in even more remote areas?

In view of these questions, the actual edition of the Pipeline Technology Journal contains interesting articles about developing and applying an ILI solution for deep water pipelines, researching the stability of pipelines on dynamic seabed, as well as challenging aspects in supplying line pipe to an offshore pipeline construction project and developing pipeline designs for ultra-deep sea environments.

Likewise, the PTC chairs have received your numerous abstract proposals to the upcoming 14th Pipeline Technology Conference, from March 19 to 21, 2019 in Berlin. We thank you very much for your contributions and invite you to participate in a broader collaboration about our mission of making energy infrastructures safer, more reliable, and prepared for the future. 'Energiewende' is a German word and translates into various aspects. However, in analyzing the technical core and discussing long-term solutions for an increasingly involved public we all speak the same language. Please take advantage of our early bird incentives and register until November 30 for the PTC 2019. By now, we look forward to seeing you all in Berlin next year.

Yours,

> Steffen Paeper, Senior Offshore Commissioning Engineer, South Stream Transport B.V.

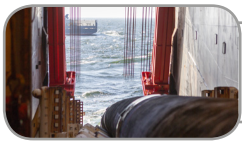
Member of the Pipeline Technology Conference Advisory Committee

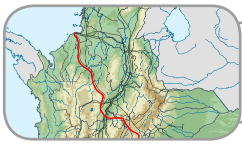
OCTOBER 2018 / ISSUE 4

THIS ISSUE'S COMPLETE CONTENT

TECHNICAL ARTICLES

RESEARCH / DEVELOPMENT / TECHNOLOGY





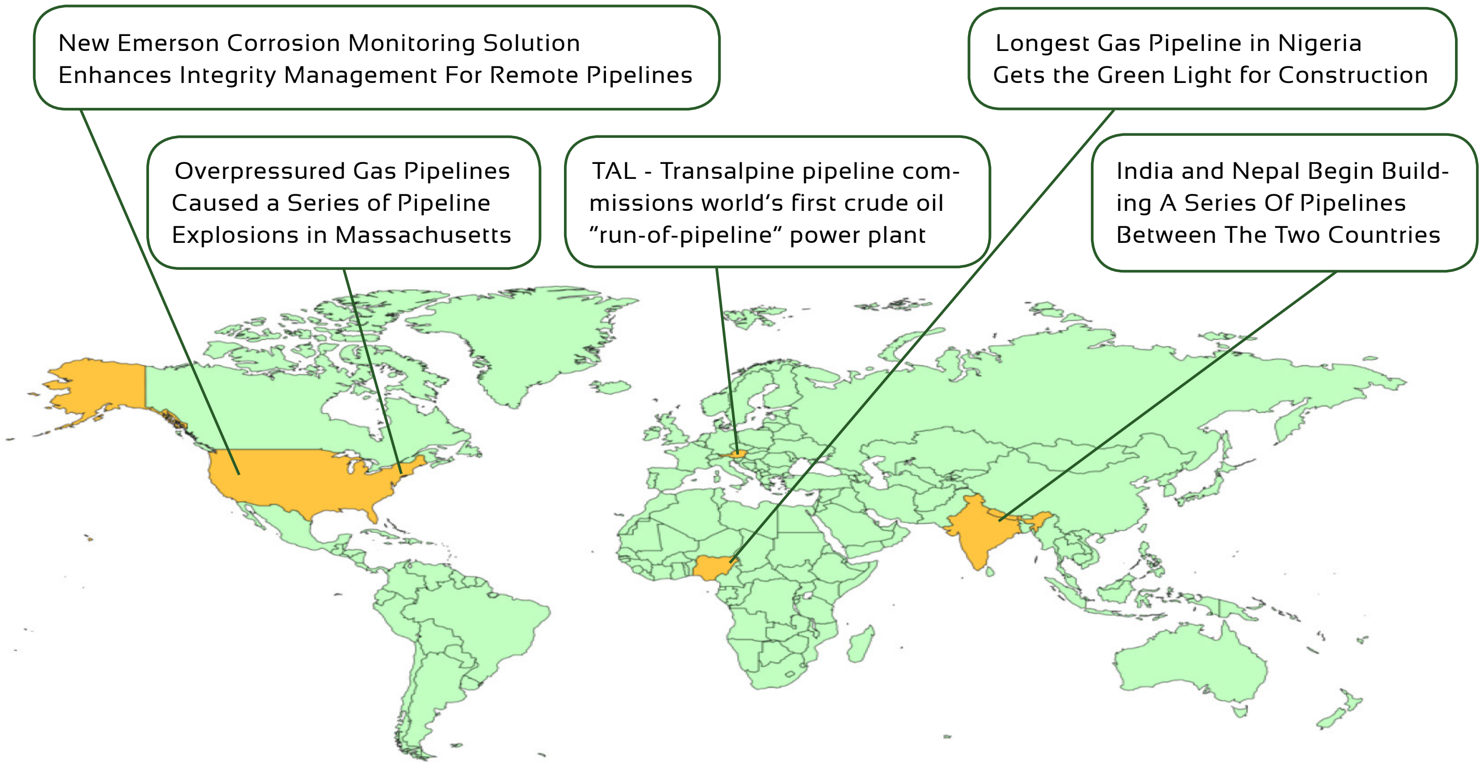
INDUSTRY NEWS

REPORTS

CONFERENCES / SEMINARS / EXHIBITIONS

www.linkedin.com/groups/4740567
www.twitter.com/pipelinejournal
www.facebook.com/Pipeline.Technology.Conference
www.pipeline-journal.net

WORLD NEWS



Pipeline Technology Journal
www.pipeline-journal.net
ptj@eitep.de

Publisher
Euro Institute for Information and Technology Transfer GmbH
Am Listholze 82
30177 Hannover, Germany
Tel: +49 (0)511 90992-10
Fax: +49 (0)511 90992-69
URL: www.eitep.de

President: Dr. Klaus Ritter
Register Court: Amtsgericht Hannover
Company Registration Number: HRB 56648
Value Added Tax Identification Number: DE 182833034

Editor in Chief
Dr. Klaus Ritter
E-Mail: ritter@eitep.de
Tel: +49 (0)511 90992-10

Editorial Board
Advisory Committee of the Pipeline Technology Conference (ptc)

Editorial Management & Advertising
Admir Celovic
E-Mail: celovic@eitep.de
Tel: +49 (0)511 90992-20

Design & Layout
Michael Hasse: hasse@eitep.de

Editorial Staff
Dennis Fandrich: fandrich@eitep.de
Mark Iden: iden@eitep.de

Terms of publication
Six times a year, next issue: November 2018
Material Deadline: October 31st 2018

Overpressured Gas Pipelines Caused a Series of Pipeline Explosions in Massachusetts, USA

The residents of a small part of eastern Massachusetts were shaken by an natural gas disaster. The people of Lawrence, Andover and North Andover just south of the New Hampshire border, witnessed dozens of homes explode last Thursday, while homeowners rushed to evacuate and turn off the gas. State and federal authorities are investigating after at least 60 fires and explosions traced to gas lines erupted Thursday, killing an 18-year-old man and injuring multiple people.

The reason for this incident: too much natural gas was pumped into a section of pipe owned by Columbia Gas, causing the combustible fuel to leak into homes, authorities said Sunday. The National Transportation Safety Board "can confirm at this time that this was indeed an overpressure situation," NTSB Chairman Robert Sumwalt said at news briefing.

This violent tragedy hits a region that is already struggling to provide for its own energy needs. For several years now, local and state governments in New England, particularly in Massachusetts, have been fighting the construction of new natural gas pipelines. The argument against new pipelines has been an environmental one spiced with fears of disaster. Thousands of miles of natural gas pipelines in Massachusetts are leak-prone and need repair, utilities have told state regulators, highlighting aging energy infrastructure risks.

What happened in Massachusetts is not something previously experienced. Such a fatal incident has been unprecedented, until now.

EDITORS COMMENT:

We can't get back to business as usual after the accident in Massachusetts. We have to adjust our behavior.

When we think of the reports about the pipeline accident in Massachusetts, we first think of those affected by the accident who suffered physical damage or even died. And we think of those who, due to the accident, have to continue their lives without the usual atmosphere of safety in their homes, those who will have to wait a long time until everything is back to the way it used to be prior to the accident.

Such a tragic accident also concerns everyone in the pipeline industry worldwide, because it destroys what we have worked for so hard in recent years: trust. We will soon have to struggle even harder for that trust, or public perception, when it comes to laying a new, necessary pipeline or repairing or reconstructing an old one. Such tragedies also destroy efforts to make the pipeline industry more attractive to junior staff. It will be even more difficult for us in the future to get well-trained employees to join our industry.

In future, we will therefore have to make even greater efforts to convey to the public, both to the authorities and to the population, the impression that pipelines represent only a minor risk if the necessary care is executed in the planning, construction and operation of pipelines.

We as planners and organizers of a major pipeline technology show and as editors of the international Pipeline Technology Journal (ptj) have long since recognized this task and have therefore for many years placed our Pipeline Technology Conference (ptc) in Berlin under the main heading of safety in the pipeline industry. Recently, we have increasingly focused on people and the impact of our actions on the outside world and have received a great deal of support for it. This support ultimately led us to add two side conferences to the Pipeline Technology Conference, one on Public Perception and the other one on Qualification & Recruitment.

These measures alone are not enough to achieve and maintain a positive image of the pipeline industry. We need to change our behavior and to make our safety efforts pro-actively known to the public. We should also strive to take new paths regarding education and training in order to develop the appropriate skill sets among employees at all levels of the pipeline companies. We can do this, but we have to develop the right instruments and for this we should exchange information on the international level in lectures and discussions in order to sort out the best solutions for the global pipeline industry and for all of its companies.

VERSATILE.

Always a leading innovator, we supply customers with cutting-edge diagnostic and system integrity solutions. This, bound with our focus on flexibility, reliability, cost and quality, leads to offerings beyond your expectations.

Luis D'Angelo, Sonia Furtado, Olav Fyrileiv, Leif Collberg > DNV GL

ULTRA-DEEP WATER DEPTH PIPELINES: DESIGN CRITERIA REVIEW FOR NEW FRONTIER APPLICATIONS

Pipelines in ultra-deep water depth are generally associated with design and installation technical challenges. Research and development efforts to improve reliability and efficiency of subsea pipelines, keeping the associated risks within an accepted range, are still a must. Improvement of the pipe steel grade quality, manufacturing innovations, installation methods, lay-vessel capacity, and design criteria optimization such as in DNVGL-ST-F101 (2017) and API-RP-1111 (2015) focusing on the physical failure modes, are very welcome to the pipeline industry. Such improvements have arisen by the demands from the new frontiers where the pipelines are required to operate in harsh environments.

The intention of this paper is to review the so-called wall thickness design criteria well established in the oil and gas industry for ultra-deep water scenarios, reflecting pressures only and constituting the minimum wall thickness that can be used: the pipeline wall thickness design for pipe pressure containment (bursting), local buckling (system collapse) and propagating buckling as outlined in DNVGL-ST-F101 and API-RP-1111.

In addition, the safety philosophy and code limitations are discussed, and the main differences are illustrated using a design example of an ultra-deep water pipeline application. A set of requirements is also shown that allows for replacing the system pressure test. Such a possibility could reduce costs related to pre-commissioning by minimizing time spent on offshore campaigns.

INTRODUCTION

The installation of subsea pipeline, aimed to transport oil and gas, is affected by economic, technical and environmental parameters. The basis for the pipeline design consists of its functional requirements, the definition of the environment, the selection of the mechanical design, installation method, optimal routing, on bottom stability criteria, free spanning, pipe-soil interaction and linepipe specification including supplementary requirements. Other important data parameters include flow assurance, pressure containment, design temperature and pressure, maximum and minimum operating pressure and temperature, incidental operation details, corrosion allowance, sweet or sour service definition and pipeline protection.

Traditional pipeline and riser design codes were based on classical Allowable Stress Design (ASD) format. A Load and Resistance Factor Design (LRFD) code format, based on the limit state design, was then introduced and gained importance. Driven by new pipeline developments, the LRFD method was introduced in DNV96 in 1996 as the basis to limit the loading of a structure based on the structural reliability approach.

The transformation from classical ASD to the LRFD format, as discussed by Collberg et al. (2001), expresses the fundamental principle "to verify that design load effects (LSd), do not exceed design resistances (RRd), for any considered failure modes and load scenarios". The design load effect "is obtained by combining the characteristic load effects from different load categories and certain load effect factors. A design resistance is determined by dividing the characteristic resistance by resistance factors that are dependent on the safety class, reflecting the consequences of the failure" (DNVGL-ST-F101).

The load and resistance factors depend on the Safety Class (SC), which characterizes the consequences of failure. This philosophy makes a difference when dealing with challenging ultra-deep water pipelines. From this approach, the determination of the selection of characteristic resistance and load effects and the partial safety factors introduces a more efficient influence due to the material and load uncertainty parameters.

SAFETY PHILOSOPHY

The safety factors which depend on the safety class (SC) are the resistance strain factor (γ_ε), safety class resistance factor ($\gamma_{sc,i}$), and pressure test factors (α_{mpt} and α_{spt}), as stated by LRFD design format.

Consequences to environment, asset and people can often be achieved based on the content and location of the pipeline therefore, DNVGL-ST-F101 recommends

> *"The purpose of this article is to review the wall thickness design criteria for subsea pipelines outlined by API and DNV GL standards as well as discuss safety philosophy and code limitations.*
> Luis D'Angelo

the pipeline by its location class and fluid category in compliance with ISO 13623. Location class 1 is the area where no human activity exists or is very unlikely along the pipeline route, while location class 2 is the section of the pipeline or riser near the platform area or in areas with frequent human presence such as landfalls. To extend the location class 2, an appropriate risk analysis should be performed; otherwise, a minimum horizontal distance of 500 m is assumed.

It follows that the "safety class may vary for different construction or operational phases and locations". Safety class Low is defined as a failure with small or negligible risk of human injury and minor environmental and financial consequences. Safety class Medium is a failure with low risk of human injury, high political or financial consequences, and minor environmental pollution. Safety class High is a failure with risk of significant environmental pollution, or very high financial or political consequences and human injury. For each Low, Medium or High safety class, the associated safety factors are given. The structure shall be designed considering the probabilities and consequences of failure associated with the risk, a combination of probability of failure and consequence of failure.

The SUPERB project (Jiao et al. 1996) established the basis for the pipeline structural reliability by collecting a large quantity of statistics data for loads, material properties and dimensions. Then, the nominal target probability of failure was determined using Structural Reliability Analyses (SRA) and reversed engineering to determine the inherent safety level of existing pipelines with a safety level considered acceptable by the society at large.

Per DNVGL-ST-F101, as an option to the specific LRFD and ASD formats, a recognized structural reliability analysis-based design method may be applied, if the method complies with DNV Classification Note No. 30.6. The reliability based limit state shall not be used to replace the safety factors for pressure containment criterion except for accidental pressure (applicable to HIPPS based systems). This is in line with ISO 13623 which states that SRA methods are not allowed to modify the pressure containment safety factors. DNVGL-ST-F101 Section 2.3.5 explains that "as far as possible, nominal target failure probability levels shall be calibrated against identical or similar pipeline designs that are known to have adequate safety on the basis of this standard. If it is not feasible, the nominal target failure probability level shall be based on the nominal annual probability of failure versus safety class as given in Table 2-5" Sec. 2.3.5 in DNVGL-ST-F101.

The table also reflects the higher conservatism in the pressure containment formulation, as detailed by Agrell and Collberg (2017). SRA can be used to optimize the safety factors for specific cases and applied on new innovative solutions, new technology and deeper waters.

DESIGN CRITERIA – DNVGL-ST-F101

The limit state design implies that the pipeline design is to be checked for all relevant failure modes. Failure modes vary in criticality and are split into limit state categories; the serviceability limit state (SLS), ultimate limit state (ULS) with the sub-categories fatigue limit state (FLS) and accidental limit state (ALS) categories. The limit state checks are also split into different scenarios which may include different limit states as given in Table 5-7, Sec. 5.4.1.1 presented in DNVGL-ST-F101.

The pressure containment (bursting) design shall be based on the pressure without pressure drop due to friction, and this condition is achieved if the flow is stopped. The pressure shall be adjusted for the column weight; the pressure shall therefore be calculated for every elevation, referred to as the local pressure. The pressure containment shall fulfill the equations (1) and (2) in Table 1.

The local buckling design implies gross deformation of the cross section. The external pressure at any point along the pipeline shall fulfill the equations (5) to (8), for the system collapse check. The weakest section of a seamless produced line pipe section may not be well represented by the minimum wall thickness since it is not likely to be present around the whole circumference. "A larger thickness, between t_1 and t_2, may be used for such pipes if this can be documented representing the lowest collapse capacity of the pipeline" (Sec. 5.4.4.1). This collapse formulation is taken from Haagsma (1981) formula as discussed by Murphy and Langner (1985).

In line with the discussion of pressure containment, system effects are present for collapse and the minimum thickness, t_1, shall be used. To obtain the nominal wall thickness, the fabrication tolerance and the corrosion allowance need to be added to t_1.

Collapse is often only considered for the temporary phases where irrelevant corrosion damage exists, and as such, the corrosion allowance may be neglected. However, collapse also might become relevant in the operational phase, especially for depressurization of gas lines, and in those cases, should be considered for the operational phase. The collapse formulation is a combination of the plastic collapse, pp, and elastic instability, pel. Full scale tests have demonstrated that welded pipes have a lower collapse capacity than seamless pipes. This has been explained by the fact that the compressive yield stress is lowered by the expansion forming step of welded pipes due to the Baushinger effect. The maximum fabrication factor α_{fab} of 0.85 for UOE pipes is recommended to be used as a penalty for that, per DNVGL-ST-F101. A lot of work by different pipe manufacturers has been invested in modifying the pipe forming process and taking advantage of light heat treatment to achieve a higher fabrication factor. This illustrates another advantage with the limit state based format that shows the importance of the compressive yield strength.

Pressure containment	$p_{li} - p_e \le Min\left(\frac{p_b(t_1)}{\gamma_m \gamma_{sc}}; \frac{p_{lt}}{\alpha_{spt}} - p_e; \frac{p_h \cdot \alpha_U}{\alpha_{mpt}}\right)$ (1) $p_{lt} - p_e \le Min\left(\frac{p_b(t_1)}{\gamma_m \gamma_{sc}}; p_h\right)$ (2) $p_b(t) = \frac{2t}{D-t} f_{cb} \frac{2}{\sqrt{3}}$ (3) $f_{cb} = Min\left[f_y; \frac{f_u}{1.15}\right]$ (4)	p_{li} = local incidental pressure, p_{lt} = local test pressure (system test), α_{spt} = system pressure test factor, α_U = material strength factor, α_{mpt} = mill pressure test factor, p_b = pressure containment resistance p_h = mill test pressure. γ_{sc} = safety class resistance factor γ_m = material resistance factor p_c = collapse pressure, p_{el} = elastic collapse pressure, p_p = plastic collapse pressure, D = nominal outside diameter, f_y = yield strength, α_{fab} = fabrication factor p_e = external pressure, p_{min} = minimum internal pressure that can be sustained, t = wall thickness which in (1) should be taken as the minimum wall thickness (t_1). t_2 = wall thickness used to represent local effects; $t_1 = t - t_{fab}$ (Prior to Operation) $t_1 = t - t_{fab} - t_{corr}$ (Operation) $t_2 = t$ (Prior to Operation) $t_2 = t - t_{corr}$ (Operation) f_o = ovality $f_o = \frac{D_{max} - D_{min}}{D_{nom}}$ f_o minimum = 0.5 f_o maximum = 3%
Local Buckling	$p_e - p_{min} \le \frac{p_c(t_1)}{\gamma_m \gamma_{sc}}$ (5) $(p_c(t) - p_{el}(t))(p_c(t)^2 - p_p(t)^2) = p_c(t) p_{el}(t) p_p(t) f_o \frac{D}{t}$ (6) $p_{el} = 2E \frac{\left(\frac{t}{D}\right)^3}{1-\nu^2}$ (7) $p_p = f_y \alpha_{fab} \frac{2t}{D}$ (8)	
Propagation buckling	$p_e - p_{min} \le \frac{p_{pr}}{\gamma_m \gamma_{sc}}$ (9) $p_{pr} = 35 f_y \alpha_{fab} \left(\frac{t_2}{D}\right)^{2.5}$ For 15<D/t_2<45 (10)	

Table 1: DNVGL-ST-F101 Criteria

Propagation buckling is initiated only if a local buckling has occurred. When the external pressure exceeds the propagating buckling criterion, buckle arrestors should be installed as the consequences of failure is so extra ordinary. This design philosophy is similar to requirements to running fracture of a gas pipeline. The spacing between the devices is determined based on cost and spare pipe philosophy. The propagating buckle criterion check shall fulfill the equations (9) and (10) in Table 1 where t_2 is the wall thickness representing local effects.

DESIGN CRITERIA - API

The criteria used for internal and external pressure by API-RP-1111 are summarized in Table 2. Pressure is interpreted as the difference between internal pressure and external pressure acting on the subsea pipeline. The pressure containment prediction (burst) is based on equations (11) and (12). The criterion states that the effective tension due to static primary longitudinal loads shall not exceed the value given by equation (13), where the physical meaning of the term "effective" relates to the interaction between the pipe and other structures.

The combination of the differential pressure load and the primary longitudinal load (static and dynamic) shall not exceed that given by equation (14). API provides a criterion for maximum differential pressure as well as a formulation to approximate the collapse pressure. The criterion states that the "collapse pressure of the pipe shall exceed the net external pressure everywhere along the pipeline" per the equation (15).

Note that the API collapse factor ratio of 0.7 and 0.6 is identical to the α_{fab} of DNVGL-ST-F101, and similarly this ratio may be increased from 0.7 to unity by moderate heat treatment, e.g. during coating. Equations (16) through (18) are used to calculate the collapse pressure and do not include the ovality. API-RP-1111 includes ovality in the combined bending and external pressure criterion (19). The collapse factor fc is included in equation (19) in API-RP-1111 (2011 edition) to reflect consistency with the DNV GL design code. API-RP-1111 defines propagating buckling as a buckle resulting from excessive bending or another cause that propagates along a pipeline caused by the hydrostatic pressure. The propagating buckle criterion is given in equations (20) and (21) in Table 2.

Internal Pressure Design (bursting)	Internal Pressure (burst) Design	$p_b = 0.45(S+U)\ln\frac{D}{D_i}$ For D/t<15 (11) $p_b = 0.9(S+U)\frac{t}{D-t}$ For D/t>15 (12)	D = nominal outside diameter, D_i = inside diameter S = minimum yield strength, U = minimum ultimate tensile strength, ln = natural log. T_{eff} = effective tension in pipe T_y = Yield tension in pipe Ta = Axial tension in pipe σ_a = Axial stress in pipe wall f_o = collapse factor (0.7 for seamless or Electric Resistance Welded (ERW) pipe and 0.6 for cold expanded pipe) f_c = collapse factor for use with combined pressure and bending loads (API Section 4.3.2.3) g = collapse reduction factor E = modulus of elasticity, P_e = elastic collapse pressure P_y = yield pressure at collapse P_c = collapse pressure P_b = Burst pressure f_P = 0.80 P_o = external pressure P_i = internal pressure, t = nominal wall thickness Pp = Propagating pressure
	Longitudinal Load Design	$T_{eff} \le 0.60 T_y$ (13) $T_{eff} = T_a - P_i A_i + P_o A_o$ $T_a = \sigma_a A \quad T_y = SA$ $A = A_o - A_i = \frac{\pi}{4}\left(D^2 - D_i^2\right)$	
	Combined Load Design	$\sqrt{\left(\frac{P_i - P_o}{P_b}\right)^2 + \left(\frac{T_{eff}}{T_y}\right)^2} \le \begin{bmatrix} 0.90 \\ 0.96 \\ 0.96 \end{bmatrix} \begin{bmatrix} operational\,loads \\ extreme\,loads \\ hydrotest\,loads \end{bmatrix}$ (14)	
External Pressure (collapse) Design	Collapse due to External Pressure	$f_o P_c \ge (P_o - P_i)$ (15) $P_c = \frac{P_y P_e}{\sqrt{P_y^2 + P_e^2}}$ (16) $P_y = 2S\left(\frac{t}{D}\right)$ (17) $P_e = 2E\frac{\left(\frac{t}{D}\right)^3}{(1-\nu^2)}$ (18)	
	Buckling Due to Combined Bending and External Pressure	$\frac{\varepsilon}{\varepsilon_b} + \frac{(P_o - P_i)}{f_c P_c} \le g(\delta) = (1+20\delta)^{-1}$ (19)	
	Propagating Buckling	$P_o - P_i \ge f_p P_p$ (20) $P_p = 24S\left(\frac{t}{D}\right)^{2.4}$ (21)	

Table 2: API-RP-1111 Design Criteria

CORROSION ALLOWANCE

API-RP-1111 refers to ASME B31.4 for liquid pipelines, ASME B31.8 for gas pipelines, and NACE SP 0607 to prevent internal and external corrosion. It states that a corrosion allowance for external corrosion is not required where cathodic protection (CP) is provided, and for internal corrosion, the pipe wall thickness may require a corrosion allowance; however, its determination is outside the scope of the recommended practice.

ASME B31.8 states that due to the corrosivity of hydrogen sulfide and the frequent presence of carbon dioxide and salt water (corrosive), special emphasis shall be given to internal corrosion mitigation and monitoring for gas pipelines. It states that internal corrosion and erosion require special consideration from case to case and a combination of inhibitors and/or corrosion allowance.

Corrosion allowance by DNVGL-ST-F101 may suit to compensate for external and/or internal corrosion, but is mainly to control that the capacity of the pipe is sufficient despite corrosion attacks/defects. In the case of C-Mn steel components, corrosion allowance may be utilized either alone or in addition to other systems to mitigate the corrosion.

However, for external corrosion protection of continuously submerged components, cathodic protection is mandatory and a corrosion allowance for external corrosion control is then superfluous. A minimum internal corrosion allowance of 3 mm is recommended for C-Mn steel pipes of safety class medium and high transporting hydrocarbon fluids likely to contain liquid water during operation. For dry gas and other non-corrosive fluids, no corrosion allowance is required. For C-Mn steel risers of safety class medium and high in the splash zone a 3mm, external corrosion allowance is recommended.

For risers carrying hot fluids (> 10°C above normal ambient seawater temperature), a higher corrosion allowance should be considered, at least for the splash zone.

It should be noted that a corrosion allowance is a simplified design approach used in the design phase. More detailed knowledge about the corrosion pattern can be utilized in bursting integrity assessment in the operation phase in line with DNVGL-RP-F101 or ASME B31.G. Similar guidance does not exist for collapse capacity.

MATERIAL TEMPERATURE DE-RATING

Material temperature de-rating in API-RP-1111 is represented by the temperature de-rating factor, ft, in equation (1) of Section 4.3.1, and is used as a safety factor on Pb to obtain the hydrostatic test pressure, Pt. The temperature de-rating factor is specified in ASME B31.8 (2014). Note that API-RP-1111 doesn't de-rate due to temperatures lower than 121°C while DNVGL-ST-F101 applies de-rating from 50°C in line with ISO 13623. As discussed by Bredenbruch et al. (2006), the material properties are established at room temperature and should be modified to any temperature deviating from this.

DNVGL-ST-F101 describes material temperature de-rating in Section 5.3.3.4 and is represented as two factors, f_u,temp and f_y,temp, which are the de-rating values for the tensile strength and yield limit, respectively. De-rating values are deducted from SMYS and SMTS to obtain a characteristic material strength. These characteristic material strengths, are in turn used throughout for various limit states. An important observation is that the de-rating curves proposed in Section 5.3.3.4 of DNVGL-ST-F101 are only there for application in cases where no other information is available; material testing can be used to lower the de-rating values.

PRESSURE TEST PHILOSOPHY

In API-RP-1111, the maximum operating pressure (MOP) shall not exceed the design pressure of any component, including pipe, valves and fittings. In addition, it shall not exceed 80% of the applied hydrostatic test pressure implying a testing after-construction of no less than 125% of the MOP. To ensure no leaks, the pipeline system must be maintained continuously at maximum test pressure for a minimum of eight hours. The design pressure is the pressure for which the pipe wall is designed and MAOP is the proof-tested pipe pressure, which must be less than or equal to the design pressure.

In DNVGL-ST-F101, the pressure containment capacity shall be ensured by the design criteria and safety factors. Pressure testing is split into two: strength testing (mill test for pipe joints and hydrostatic testing of components) and in-situ leak test (pipeline system pressure test). The system pressure test should be 5% above the local incidental pressure or 3% for safety class low. The incidental pressure is typically 0 to 10% above the design pressure depending on the degree of control and accuracy in the pressure safety system. Thus, a system pressure test of approximately 1.15 times the local design pressure is required for safety class Medium and High at the highest point (given that the test medium density is higher than α_{spt} * density of the medium in operation of the pipeline system part tested). This difference will normally increase for deeper sections of the pipeline since the test fluid is water with a density greater than that of most transported fluids.

The system pressure test is acceptable by the DNV GL code if the submarine pipeline system has no leaks, and the "pressure variation is within ± 0.2% of the test pressure". A pressure variation up to an additional ±0.2% of the test pressure is normally acceptable in case the total variation (i.e., ± 0.4%) can be documented to be caused by temperature fluctuations or otherwise accounted for. If pressure variations are greater than ± 0.4% of the test pressure, the holding period shall be extended until a hold period with acceptable pressure variation has occurred.

Given that a set of requirements are met, DNVGL-ST-F101, may allow for replacing the system pressure test, per Sec. 5.

Section 5.2.2.3 states that "for pipelines where the disadvantages with the system pressure test are extraordinary, alternative means to ensure the same level of integrity as with the system pressure test are allowed by agreement. It may be considered when all the following criteria have been met:

- The pipeline section does not contain non-welded connections unless these have been separately tested after installation in the pipeline system.
- The mill pressure test requirement of [7.5.1] has been met and not waived in accordance with [7.5.1.6].
- Extensive experience with similar pipelines documenting a good track record with respect to defects and leakages during system pressure test".

Per Section 5.4.2.1 equation (5.6), the mill pressure levels can be decreased for cases where the "pressure containment criterion is not fully utilized, e.g. installation by reeling or for ultra-deep water". Alternatives to test pressure means proving that the same level of safety as with the system pressure test is allowed by agreement given that the mill pressure test requirement has been met and not waived in accordance with requirements presented in DNVGL-ST-F101 (2017), Section 7.5.1.6. System pressure test guidelines are given in DNVGL-RP-F115.

SYSTEM COLLAPSE CRITERION

The system collapse pressure using the criterion from DNVGL-ST-F101 (2017) is compared to the local buckling criteria from API-RP-1111 and plotted against experimental test data in Figure 1. Test results from full scale tests used in the SUPERB project comprising Fowler (AGA 1990), Vogt et al. (1985), and small scale tests from Kyriakides and Yeh (1985) and (1987), Johns and McConnell (1984), Erica et al. (2012) and several other additional large and small scale test results were examined in the SUPERB project. The collapse pressure for the available test results in the literature is plotted against the diameter to wall thickness ratio (D/t) in Figure 1. From the plot results, a more conservative approach than API is obtained when considering DNV GL with ovalization and safety factors.

PROPAGATING BUCKLING CRITERION

The propagating buckling collapse pressure using the criterion from DNVGL-ST-F101 (2017) is compared to the pressure obtained using the criterion from API RP 1111 (2015) and plotted against experimental test data in Figure 2.

Test results were obtained from Kyriakides and Yeh (1986), Estefen et al. (1996), Kalmalarasa and Calladine (1988), Kyriakides et al. (1984), and Teresinha and Luis D'Angelo (2005).

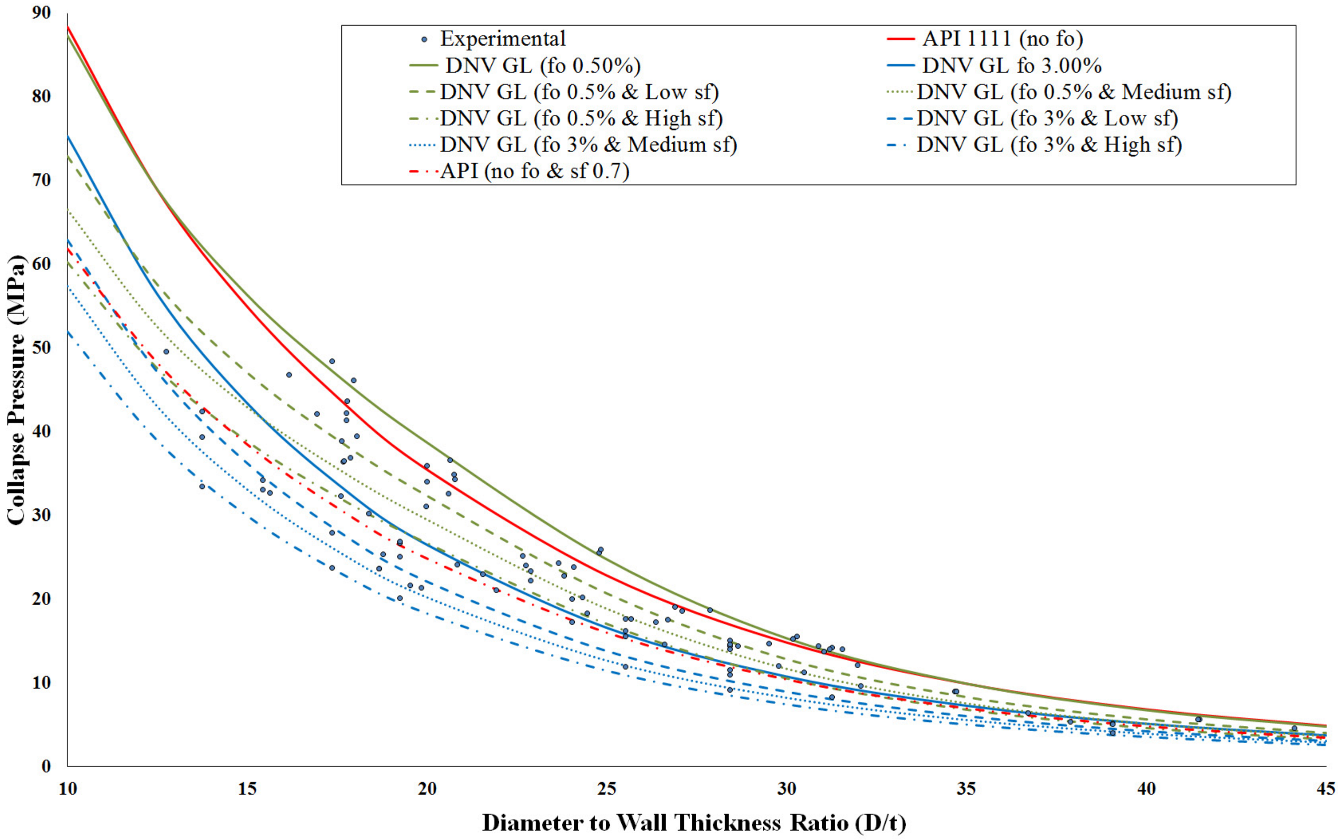


Figure 1: System Collapse Criteria vs Collapse Testing Results Comparison

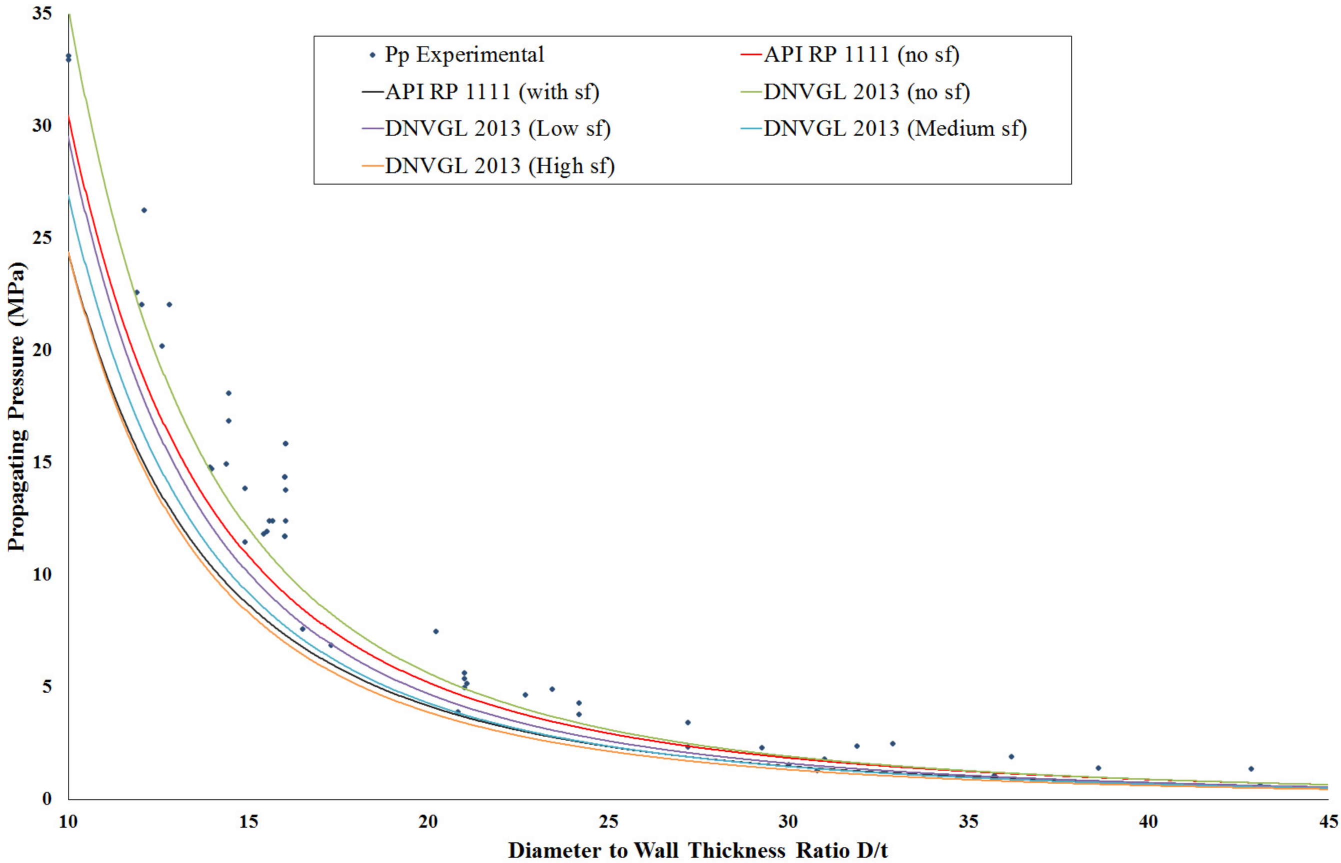


Figure 2: Propagating Buckling DNV GL vs API and Test Results

Figure 2 shows the assessment for propagating buckling pressure as a function of D/t ratio. For a D/t range between 10 and 30 and no safety factor included, API is slightly more conservative than DNV GL. It is noted that for API with safety factor 0.8, the result is similar to DNV GL with safety factor High, meaning that for Low and Medium safety factors, DNV GL allows for a thinner wall thickness than API, for propagating buckling, in case one considers designing.

CASE STUDY

To calculate the required wall thickness (t), the burst, system collapse and propagation buckling criteria need to be evaluated. The case presented shows the wall thickness design for an export pipeline from a platform to shore using API-RP-1111 and DNVGL-ST-F101.

The following pipeline data are used: water depth (WD) at platform of 2,300m, design pressure at platform of 25MPa, SG gas/oil of 0.30/0.80, export pipeline diameter 609.6mm, SMYS/SMTU of 448/530MPa and depth at shore of 12m.

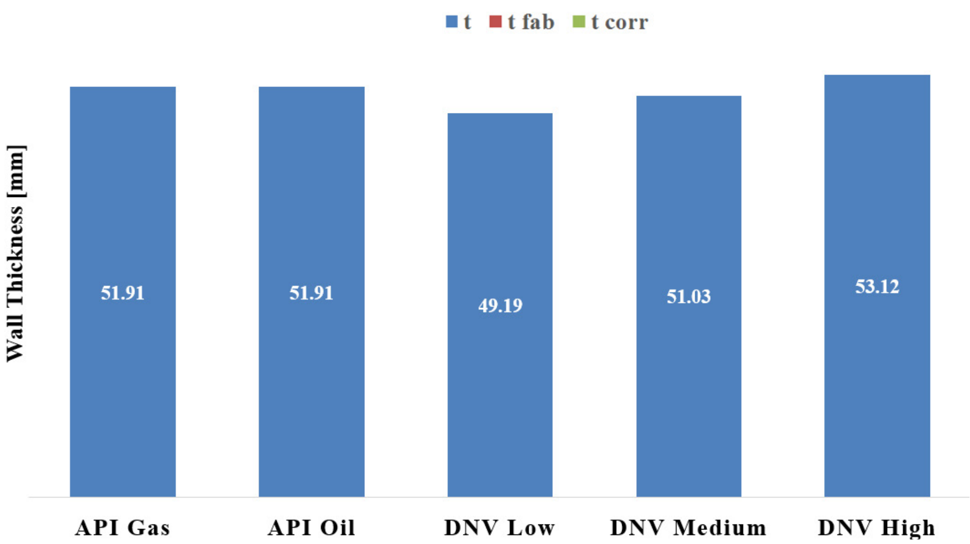


Figure 3: Wall thickness for water depth=2,300m, all Wall thickness design criteria

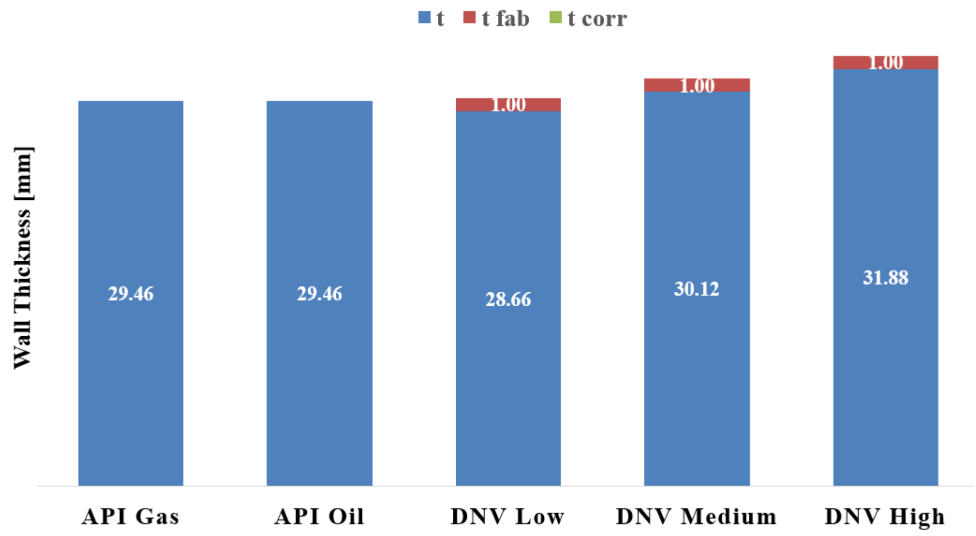


Figure 4: Wall thickness for water depth=2,300m, only collapse limit state

DNVGL-ST-F101 has more design factors than API-RP-1111, which means that either an assumption must be made or multiple results presented. To provide a complete picture the latter option is chosen.

Firstly, the safety class during operation will greatly influence the result (see Section 5.3.2.4 Table 5-2 in DNV GL). Since the fluid is either oil or gas (normally, oil and gas will result in the same safety class) and the location for the flowline is either away from the platform or inside the safety area (500m radius), results for both medium and high safety classes during operation will be presented (see Section 2.3.4.3, Table 2-4 in DNV GL). Fulfillment of supplementary requirement U in DNVGL-ST-F101 will also influence the resulting wall thickness for pressure containment (bursting).

The incidental to design pressure ratio, γ_{inc}, must be determined to calculate the necessary wall thickness. For a "typical pipeline system" γ_{inc} should be set to 1.10, in line with API-RP-1111. In the example presented, the design pressure is used; so therefore γ_{inc} =1.10. This will not affect the result when collapse is governing.

Even though there are differences in de-rating procedures in the two documents (API de-rates from 121°C and up, DNV GL de-rates C-Mn/13Cr steel from 50°C and 22Cr/25Cr steel from 20°C), no de-rating is performed for the DNV GL calculations in this example as the pipeline is likely to have an ambient temperature for the collapse scenarios considered. The reference height is set to platform so that the hydrostatic fluid column pressure in the calculation of the local incidental pressure is considered.

The ultra-deep water case (2,300m) highlights some distinctions between API and DNV GL. Figure 3 shows the resulting wall thickness by utilizing both design code formulations, while Figure 4 shows the resulting WT for the collapse criterion only.

The governing limit state is the propagating buckling for API-RP-1111 and DNVGL-ST-F101. This is an accidental limit state as it is not expected to occur but as the consequence of such a failure is so extraordinary, it is recommended to limit this consequence by installing buckle arrestors with a certain spacing. Hence, if the deep-water pipeline segment is designed for local collapse or burst (whichever is more critical – in this example, collapse), the operator should install buckle arrestors. The length between the buckle arrestors should be based on the cost of spare pipe philosophy. This will result in significant savings in the pipeline design phase.

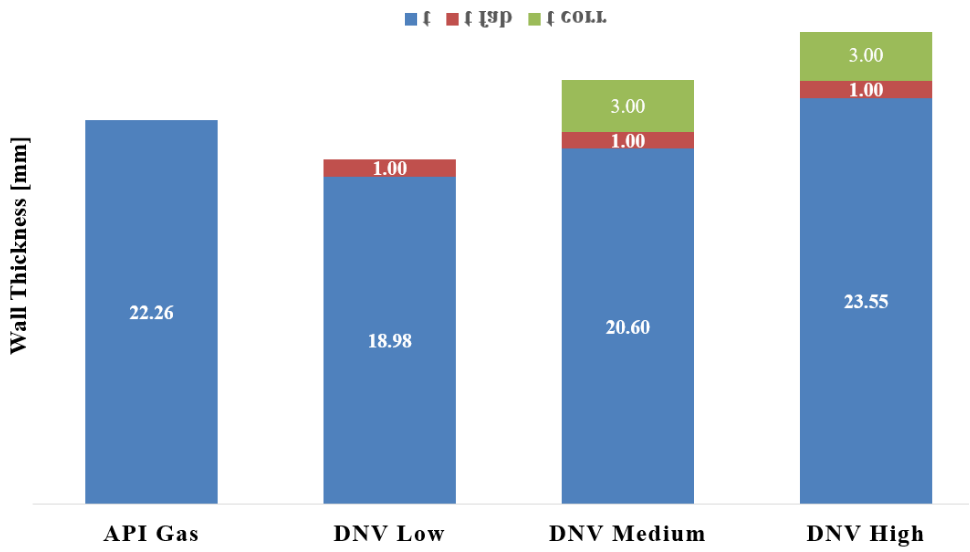


Figure 5: WT for water depth=12m (shore approach), gas - burst limit state

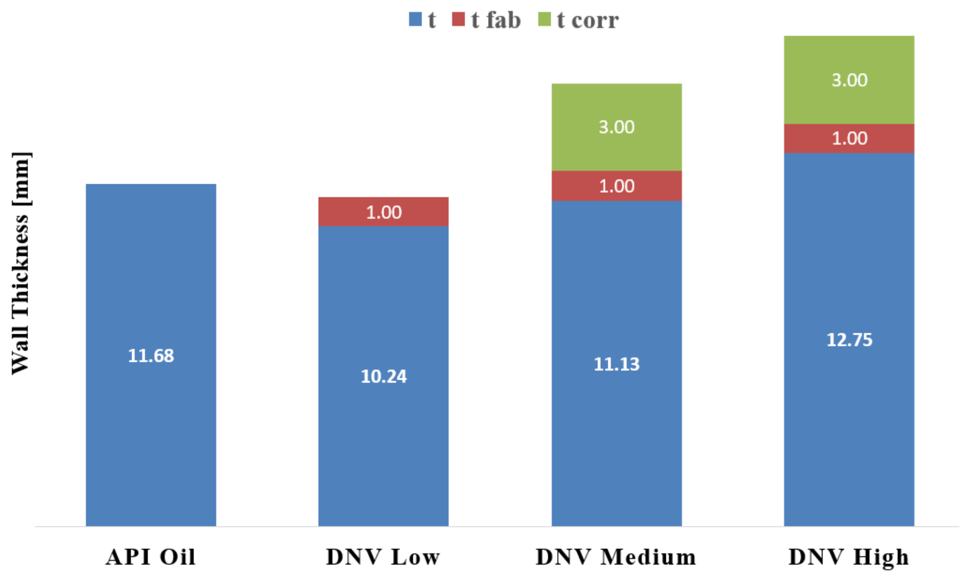


Figure 6: WT for water depth=12m (shore approach), oil - burst limit state

For bursting, API-RP-1111 uses one safety level and considers one wall thickness, while DNVGL-ST-F101 uses safety factors (Low, Medium and High) that depend on the fluid and the location, meaning that different values for wall thickness will be found at the end.

API-RP-1111 has two formulations depending on the D/t ratio; one limited to D/t ratio < 15, and the other to D/t ratio > 15. DNVGL-ST-F101 has only one formulation and the background documentation to the API RP1111 does not indicate why two different formulas should be used.

When considering local buckling (System Collapse – Figure 1), it is seen that API does not explicitly consider ovality, and DNV GL with 0.5% ovality predicts almost the same collapse capacity, except for D/t ratio between 15 and 30. In the case of the propagating buckling (Figure 3), for D/t ratio in the range of 15 and 30, API is slightly more conservative. For API with sf = 0.8, the behavior is similar to DNV GL with a high safety factor. API has no D/t ratio limitation while DNV GL's formulation is limited to between 15 and 45.

Burst is the governing criterion for the shallower sections, per both API and DNV GL, as shown in Figure 5 and 6 respectively. It is noted that for DNV GL for safety class Low and Medium, the wall thickness calculated is less conservative than that API for oil and gas, except for safety class High or if considering corrosion allowance for Medium and High.

SUMMARY AND CONCLUSIONS

The question that is asked while designing a pipeline is what is the best design code: the one that gives the thickest or the thinnest wall thickness? It can be argued that a relevant question is around consistency (i.e., non-varying safety level) and philosophy.

From the case study presented for the ultra-deep water (2,300m), the resulting WT is lowest for DNV GL safety class Low and Medium (oil and gas) followed by API (oil and gas). If collapse criterion is chosen, DNV GL is lowest for low SC (oil and gas) including tolerances, followed by API (oil and gas). For Medium and High, all wall thicknesses are in the same area with the thinnest being 30.1mm to the thickest being 31.9mm (DNV GL safety class High).

Our conclusion from this study is that DNV GL permits a more flexible and less conservative wall thickness, especially for ultra-deep water pipeline, due to the established safety philosophy.

Also, the possibility to reduce test pressure levels (both mill test and system pressure test) or waive/ replace either the mill or system pressure test, given that a set of requirements are met, speaks in favor of DNV GL code, being a flexible code that rewards extra effort in other quality control aspects of the design and manufacturing of submarine pipeline systems.

DNVGL-ST-F101 clearly states that the industry has performed quite a bit of research on the fabrication factor αfab applied to the yield stress. This has resulted in modified manufacturing techniques that can increase this factor towards 1.0, as discussed by Aamlid et al. (2011). By formulating criteria as close as possible to the physical response, the industry often picks up this challenge and brings the development further.

Finally, the primary message of this paper is not to compare equation by equation and select the minimum required thickness but highlight the different aspects to consider. In the end, an optimized ultra-deep water pipeline shall consider the totality of all these aspects: design options, capacities, fabrication, production testing and quality control.

Acknowledgments

The authors would like to thank DNV GL for its support to perform this work. Part of this work was presented at Rio Pipeline Conference and Exhibition 2017, an IBP (Brazilian Petroleum, Gas and Biofuels Institute) event.

References

- Aamlid Olav, Collberg Leif and Slater Simon: "Collapse Capacity of UOE Deepwater Linepipe", OMAE 2011.
- API-RP-1111: "Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines (Limit State design)", September 2015.
- ASME B31.G: "Manual for Determining the Remaining Strength of Corroded Pipelines", 2012.
- ASME B31.8: "Gas Transmission and Distribution Piping Systems", 2016
- ASME B31.4: "Pipeline Transportation Systems for Liquids and Slurries," 2016
- Agrell, C. and Collberg, L.:" What the ridiculously small failure probability targets really are", Offshore Pipeline Technology (OPT) Conference, 2017, IBC Energy
- Bai, Y et al: "Tube Collapse under Combined Pressure, Tension and Bending Loads", IJOPE, Vol. 3 No. 2, 1993.
- Bai, Y et al: "Collapse of Thick Tubes Under Pressure, Tension, Bending and Their Combination", Proceeding of The Second International Offshore and polar Engineering Conference, 1982, pp 568-576.
- Bredenbruch K., Gehrmann R., Schmidt T., C: "Strength de-rating of pipelines steels at elevated temperature" "3R International" 2006.
- Collberg Leif, Mork K.J and Marley M.J.: "Inherent Safety Level in Different Pressure Containment Criteria", International Offshore and Polar Engineering Conference, Stavanger, Norway, June 2001.
- DNV Classification Note no. 30.6 "Structural reliability analysis of marine structures".
- DNV'96 Rules for submarine pipeline systems, 1996.
- DNVGL-ST-F101, "Submarine Pipeline System", 2017.
- DNVGL-RP-F101, "Corroded Pipelines", May 2017
- DNVGL-RP-F115, Pre-commissioning of submarine pipelines, September 2016.
- DNVGL-RP-F110 "Global buckling of submarine pipeline design" 2017
- Erica Marley, Olav Aamlid and Leif Collberg: "Assessment of Recent Experimental Data on Collapse Capacity of UOE Pipeline" IPC 2012, Calgary, Canada.
- ISO 13623: "Petroleum and natural gas industries – Pipeline transportation systems", 2009.
- Jiao G., Sotberg T., Brushi R., Verley R. and Mork K.: "The SUPERB project: Wall Thickness Design Guideline for Pressure Containment of Offshore Pipelines" Proceeding of OMAE'96 Florence, Italy.
- Johns, McConnel: "Pipeline Design Resists Buckling in Deep Water, Oil and Gas Journal, 1984.
- Kamalarasa, Calladine: "Buckle Propagation in Submarine Pipelines, PAP88, 1988.
- Kiriakides, Yeh, Roach: "On the Determination of the Propagation Pressure of long Circular Tubes", Transactions of ASME, Vol 106, 1984.
- Leif Collberg, K.J Mork and M.J. Marley: "Inherent Safety Level in Different Pressure Containment Criteria", International Offshore and Polar Engineering Conference, Stavanger, Norway, June 2001.
- Murphy C. E. and Langner. C. G: "Ultimate Pipe Strength under Bending, Collapse and Fatigue"; OMAE'1985.
- NACE SP 0607: Petroleum and Natural Gas Industries - Cathodic Protection of Pipeline Transportation Systems - Part 2: Offshore Pipelines, 2007.
- Olav Aamlid, Leif Collberg and Simon Slater: "Collapse Capacity of UOE Deepwater Linepipe", OMAE 2011.
- Segen Estefen, Luis D'Angelo and Teresinha Alves: "Correlation between analytical and experimental results for propagation buckling". OMAE' 1996, Italy.
- Teresinha Alves and Luis D'Angelo.: "Colapso Propagante: Confiabilidade Associada a Determinacao da Pressao de Propagacao", COTEQ 2005, Salvador, Brasil.

Authors

Luis D'Angelo

DNV GL USA, Inc

Principal Engineer

Luis.dangelo@dnvgl.com

Olav Fyrileiv

DNV GL AS, Norway

Technology Leader

Olav.fyrileiv@dnvgl.com

Sonia Furtado

DNV GL USA, Inc

Senior Engineer

Sonia.furtado@dnvgl.com

Leif Collberg

DNV GL AS, Norway

Vice-President

Leif.collberg@dnvgl.com

DEEP WATER ILI TOOL DEVELOPMENT AND 5 YEARS OPERATIONAL EXPERIENCE

Olivier Gillieron, Basil Hostage, Humberto Rodriguez, Dr. Daniel Schaper > Total Exploration & Production, 3P Services

Abstract

The paper describes development of In-Line Inspection (ILI) tools and equipment for deployment in 500+m water depth offshore oil production pipelines. Various design challenges were posed by the operational conditions and the pipeline operator.

A joint development project is described in which 3P Services and Total E&P define the necessary tool characteristics, development and test program.

These challenges included: high pressure tool body design (considering the resulting limited internal space available for on board systems), bi-directional inspection operation capability, ability to negotiate flexible risers without damage to the riser's internal carcass.

Non tool related developments were also required to prepare a locating device for use in a stuck tool event.

After the successful development, 5 years of operational experience are reviewed summarizing lessons learned and potential for further development.

BACKGROUND

By definition, Oil and Gas industry call "Deep offshore" or "Deep water" fields all offshore fields producing at more than 500m water depth. Total E&P operates such fields since 2001.

The first deep offshore field operated by Total E&P was Girassol/Jasmin field which was discovered in 1996 and came on stream in December 2001. It is located off the coast of Angola, West Africa, in Block 17 about 210 km northwest of Luanda and at a water depth of 1.350m (4.430 ft).

It was the first step in a series of major developments in Block 17. Other developments that have come on stream following Girassol/Jasmin include Dalia, Rosa, Pazflor, CLOV, Akpo, Moho-Bilondo, Moho-Nord.

Ensuring pipeline integrity of such assets is one of the major challenges of Total E&P. In this deep water environment, inspecting pipelines and making repairs can be extremely difficult and costly.

First of all, inspection techniques typically used for onshore and topside facilities, such as direct ultrasonic mapping/scanning or radiography, were not easily transposable to deep water, largely due to lack of full "marinization" (modification for marine use and water depth limitation), safety or costs. Secondly, ROV is the only mean of accessing this water depth and of carrying out underwater inspections (visual inspection, direct ultrasonic mapping/scanning, cathodic protection (CP) measurements, etc...).

These limitations do not provide operators with sufficiently complete and reliable data to have a good visibility of the integrity status of a pipeline, to verify the efficiency of corrosion treatment and to finally make decisions on repairs and/or operating conditions.

Ineffective integrity management may lead to unscheduled production shortfalls and to HSE & regulatory non-compliance issues.

In-Line Inspection (ILI) is usually used for onshore and conventional offshore pipelines because it provides the best complete set of inspection data of a rigid pipeline.

Detection and sizing performance of ILI tools, Geometry and Metal Loss, on the current market were not fully compatible for this operation in such environment. Enhanced ILI was finally considered by Total E&P as the most realistic solution.

JOINT DEVELOPMENT PROJECT BETWEEN TOTAL E&P AND 3P SERVICES

Objective of a joint project therefore was development of appropriate ILI tools suitable for deep water inspections. The joint project was divided into a conceptual phase for specifying the tool characteristics, the tool design and assembly and an intensive evaluation phase before any inspection was conducted.

SPECIAL REQUIREMENTS FOR ILI

Pipeline details

Deep water environment implies specific design of subsea equipment and specific operating philosophy which will be described in this paragraph.

A large number of configurations exist:

- Looped configuration or single line or hybrid loop
- Flexible and rigid pipes combination
- Production bundle, Pipe-in-Pipe (PiP) and spools
- Specific subsea components: Riser Tower/Flexible/IPB (Integrated Production Bundle), FLET, SLED, Connections, Manifolds, Pig Loop

Deep offshore fields are organized in several packages which are generally:

- Subsea production System (SPS) which is composed of subsea Xmas trees, well jumpers, subsea manifold, and in one case a subsea separator unit.
- Umbilical Flowlines Risers (UFR) which has the function to route the production from the manifold to the topside or to route injection fluid (water/gas) to injections well heads. The export function (buoy excluded) is also included in this package. Riser is part of this package, different configurations exist: production flexible jumper + riser tower, flexible riser (Lazy-wave or Lazy-S, Integrated Production Bundle (IPB), Steel Catenary Risers (SCR).
- Floating unit package.
- Topside packages.

Pipelines, which have the function to route a fluid from one point to another, are part of the UFR package. They are typically flowlines (from subsea manifold to topside or reverse) or export lines in deep water fields within Total E&P:

- Total pipeline length: more than 900km
- Various diameters from 8 inches to 24 inches
- Pipeline material: API 5L X65 and X70
- Pipeline function: oil/gas production, water injection, gas injection, oil/gas export
- Pipeline not always equipped with pig launcher/receiver
- Constant pipeline ID

All those specific configurations and equipment make operation of deep offshore fields particular, especially for pipeline inspection by comparison to standard offshore pipelines. Pipeline cleaning is also a significant issue; if operational pigging can be regularly carried out for production loops or hybrid loop (with dead oil), it is a special operation for single (un-looped) lines.

Tool characteristics

ILI operation is considered as a success when the two following objectives are met:

- Safe pigging operations: the pipeline is pigged in a safe manner, without blocking pigs and without compromising its integrity.
- Efficient pigging operations: pigs are sent through the pipeline with specific objectives, thus, pig runs shall ensure reliable results.

Design of subsea equipment and specific operating philosophy oblige ILI tool enhancements, developments and adaptations. They had to fulfill the following requirements:

- Full operational capability in the high pressure environment of the deep water lines (maximum MOP of 190 bar and higher)
- Stainless steel inner carcass of flexible sections shall not be damaged by tools, either cleaning or inspection tools. Therefore any metal to metal contact must be prevented by tool design and use of appropriate material:
  - Metallic brushes shall not be used for magnetization or cleaning. Synthetic brushes can be used.
  - Magnets shall not be in contact with inner surface (standoff design)
- Capable to pass a large number of elbows up to about 100 and partly in back to back combination
- Capable to pass minimum bend radius of 5D
- Vibration and shock resistance of all components
- All electrical equipment must be rated for the hazardous area in which it is located (and be suitable to ATEX Gas Group IIA, Temperature Class T3)
- Measurement of internal pipeline diameter even in flexible sections
- Measurement capability for heavy wall

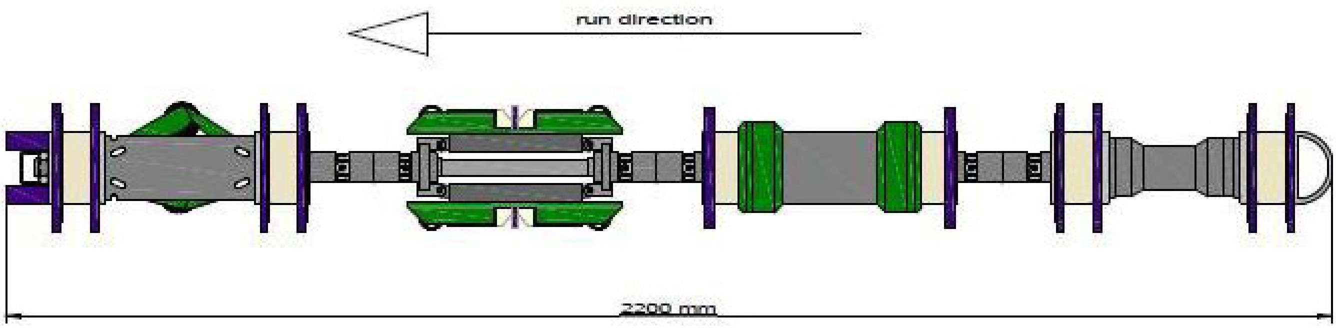


Figure 1: MFL tool design

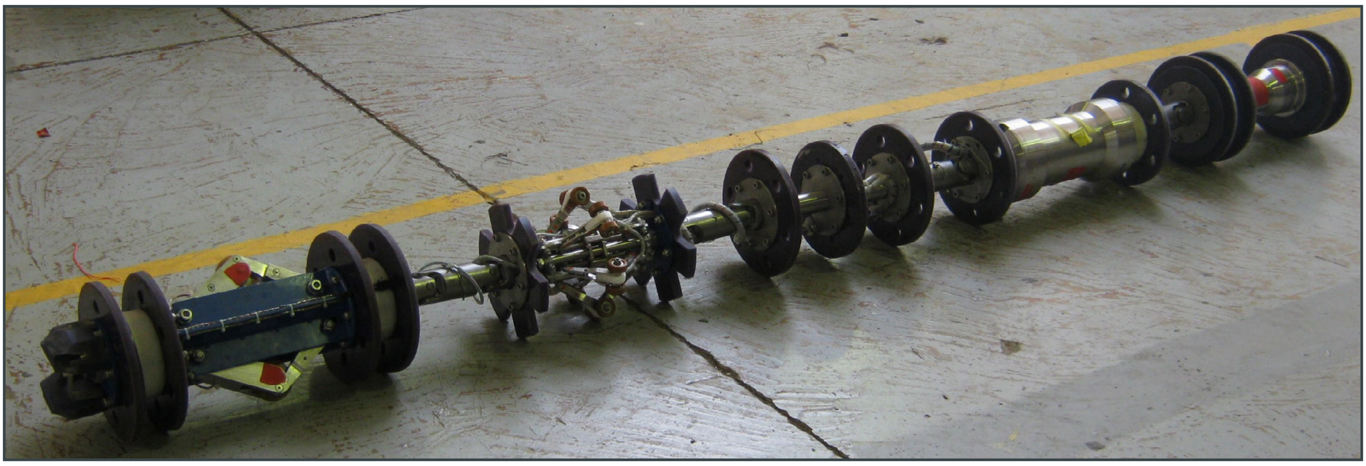


Figure 2: GEO tool with transmitter

Emergency backup

In addition to the technical requirements listed above, requirements to mitigate the risk of pig lodging (probability or consequence) were introduced by Total E&P:

- All pigs shall be able to run in reverse direction (bi-directional tools)
- All pigs shall be fitted with tracking device(s) suitable for locating a pig lodged in the pipeline and for verifying pig position within the pig launcher and receiver. It shall work on all pipelines designs and configurations (through all types of coatings and thermal insulation, etc…)

A subsea pig location device to be deployed by ROV shall be developed.

TOOL DEVELOPMENT

The initial tool development and evaluation described in this paper was focused on a set of 8" tools. Same mechanisms were applied afterwards to tools for other sizes from 8" to 24".

Tool design

In order to inspect the targeted pipelines a set of different tools was proposed to cover all measurement requirements and to ensure the passage capabilities of the tools by a successive approach. As typically used the set of tools contains a PROFILE tool with cleaning capabilities, a GEO tool and a MFL tool. The PROFILE tools with cleaning capabilities can be used to clean the pipeline on the one hand and to check the minimal pipeline diameter on the other hand. The tool has a minimal hard diameter and is equipped with several gauge plates. Any defect of the gauge plate needs to be evaluated and is used to make the decision whether the next tool having a bigger minimal diameter can be used. For cleaning purpose the PROFILE and cleaning tool is equipped with several magnets collecting any metal debris in the line.

The GEO tool proposed for the targeted pipelines is used to measure the internal pipeline diameter and allows to give a statement about the position of any pipeline reduction or bend position. The GEO tool is typically the next tool after a PROFILE tool as it has a smaller minimal diameter compared to a MFL tool. The measurement of the internal diameter is performed with electromagnetic sensors located on arms measuring the distance of the body to the pipe wall. By using two opposite located arms the internal diameter can be determined.

The MFL tool is used to measure internal or external metal loss by measurement of a magnetic flux leakage of any metal loss position. In order to create a magnetic flux leakage the pipe has to be magnetized up to saturation level [1] [2]. For this reason the tool is equipped with permanent magnets and a relative massive body is needed. Therefore this tool is the last in the line of inspection tools used.

As mentioned above, the complete set of tools was designed according to the agreed criteria. Figure 1 shows a sketch of the MFL tool design. The parts in green are critical metal parts, which might get in contact to the pipe wall in a worst case scenario. Special focus was therefore made in these areas of the tool design.

Tool assembly

Figures 1 and 2 show an assembled 8" Geo and MFL tools configured for Bi-directional operations. The tools fulfill all requirements listed in the chapter above. The measurement range of the GEO is from 160 mm to 220mm diameter. The final measurement unit also carries three discs of DMR sensors. Data from the GEO tool can be aligned with data from the MFL tool after the inspection runs. The DMR sensor data will be used together with the MFL sensor data, to discriminate internal from external metal loss defects.

The MFL modules were designed, such that no metallic components of surfaces of the MFL tool will make contact with the internal surface of the pipeline, specifically with the internal surface of the flexible sections. Other parts like odometer wheels typically made of metal were assembled in Polyamide or alternative materials.

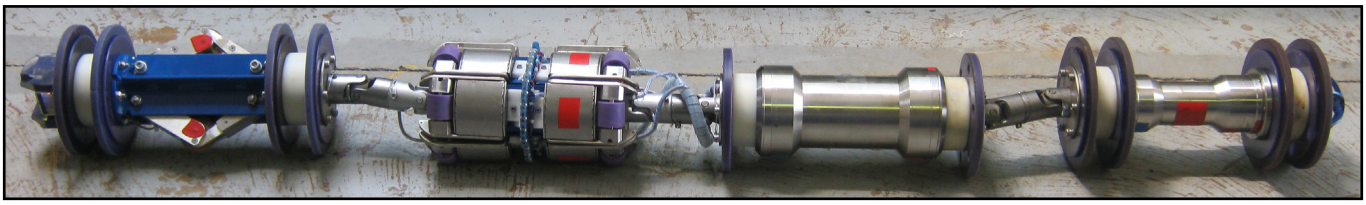


Figure 3: MFL tool with transmitter

TOOL EVALUATION

A joint final acceptance test session was performed at 3P Services' facility in Lingen in order to evaluate the tools and demonstrate the performance. On the one hand a pull test through a flexible section was performed and on the other hand the tool performance was evaluated by pump tests.

Pull test through flexible section

The objectives of the pull test through a flexible were:

- Demonstrate no damage of the flexible section by any of the tools
- Demonstrate no metal to metal contact by the tools
- Determine pulling force/Δp for the tools

The MFL tool, compared to the GEO and the PROFILE/cleaning tools, is the most critical for any potential damage or contact to the inner surface of the flexible. This is because of the heavy magnet yoke, having the largest diameter compared to any other module or component on any of the tools.

Test setup

The flexible pipe allocated from NOV weighs approx. 1.6 tons and was fixed in a test position having a 14.3 degree bend angle (Figure 4), which simulated the targeted pipeline "worst case" bend radius of 15 degree. In order to detect any potential metal to metal contact the tools were prepared with tape on the critical parts that had potential to touch the inner wall. Any metal to metal contact would harm the tape and could therefore be immediate recognized.

Condition of the flexible was checked by a video inspection before and after the pull through test in order to ensure no internal damage occurred by the targeted inspection tools.

Test execution

The tools were pulled through the flexible raiser. Figure 4 shows the MFL tool positioned in the launcher. The MFL tool was pulled by a hydraulic winch with a synthetic rope through the flexible. The rope of the winch was guided by a centering unit. The force required to pull the tool was 5687 N. This corresponds to a pressure Δp of 1.28 bars for a pipe with diameter 237.6mm. The tool speed was 0.5 m/sec. Following figure shows the MFL tool before and after the pull through tests.

Test results

Tool and flexible were evaluated in detail after the pull through test. A video inspection of the flexible showed

Figure 4: Flexible for pull test (left) / Non-metal tray as launcher (right)

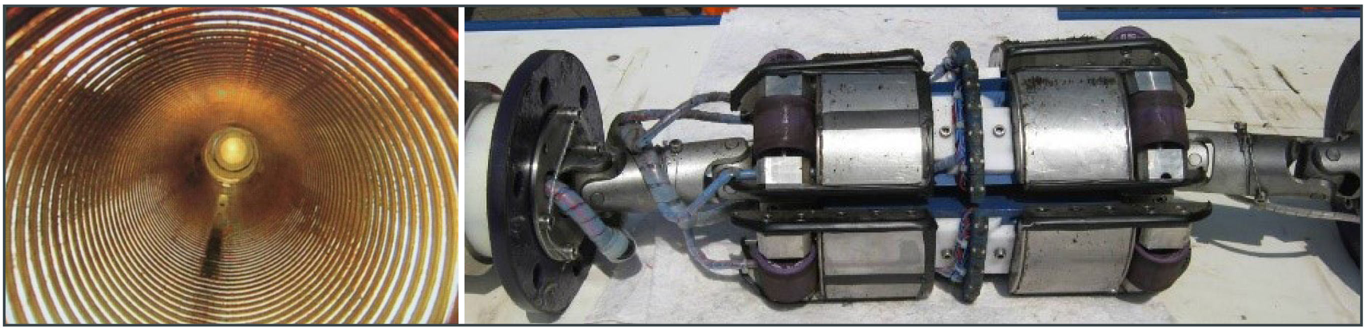


Figure 5: Screenshot of flexible (left) and undamaged masking tape (right) after pull test

no damage. Figure 5 shows a screenshot of the camera inspection and photo of the MFL measurement module after being pulled through the flexible.

The pull test proved that no metal to metal contact between tool and pipe occurred in the flexible. It could be shown that neither tool nor flexible was damaged within the pull test.

Pump test

The goal of the pump test was to evaluate and prove following points:

- Tool bend passage capability / endurance test
- Run characteristics like Δp to move the tools / blow over pressure of discs
- Detection and sizing performance / limits of measurement capability
- Magnetization level of the MFL tool
- Repeatability of the results

Pump test setup

The test facility (Figure 6) build at 3P Services has a total length of approx. 27 meters (wall thickness 14.2mm) including:

- Straight pipe with and without artificial defects in the range 10 to 80 % depth
- 4.5D bends
- Two 90°bends in back-to-back-configuration

A centrifugal pump with a maximum of 16 bars and 30 m³/h was used. Several pig locators were used to detect passage and arrival of the pig, which were placed at the ends and in the middle of the pipe.

Test loop pressure was measured at the launcher and the top side of the test facility to demonstrate the Δp across the tool.

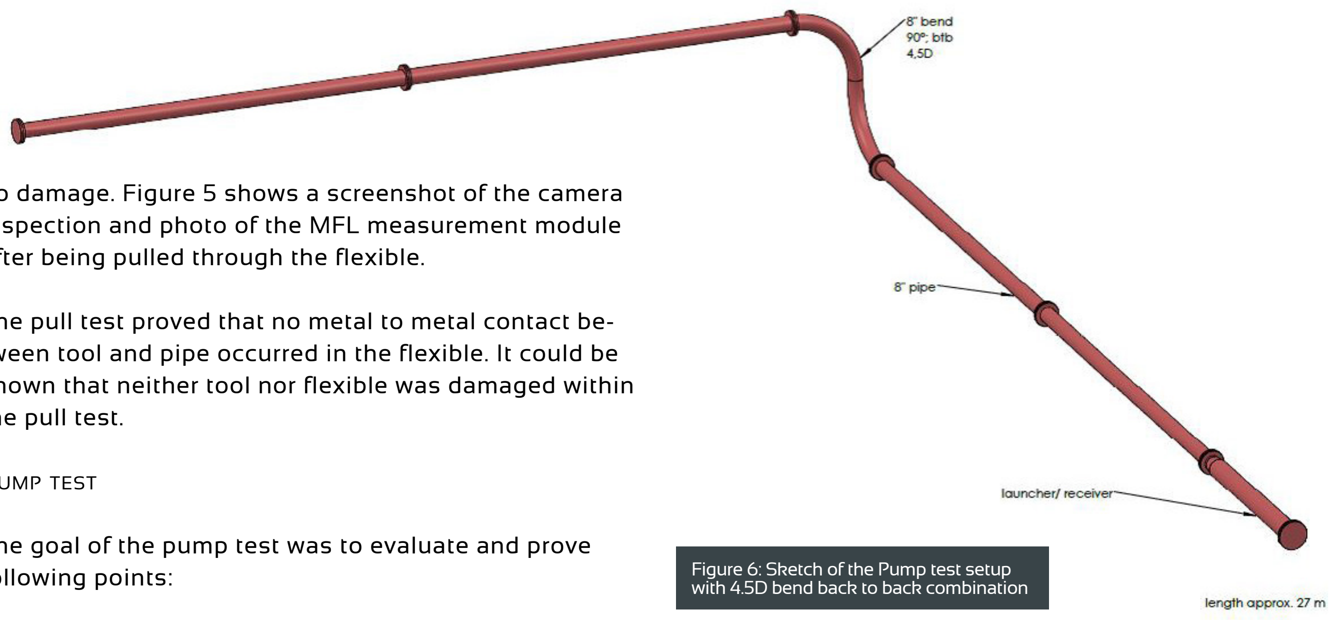


Figure 6: Sketch of the Pump test setup with 4.5D bend back to back combination

Pump test execution

All tools planned for the inspection were pumped through the test loop. The most critical tool, the MFL tool was pumped through 12 times. A 4.5D bend present in the targeted pipelines was therefore passed 48 times. The velocity of the tool was in the range of 0.45 m/s to 0.9m/s. The MFL tool measured a magnetization level of 14 kA/m for a wall thickness of 14.2 mm. The Δp to move the tools was measured between 2.5 and 3 bar. A blow over pressure test to slip the disc in order to change the direction was performed and a pressure of 4.7 bars determined.

Pump test results

All tools were in a good shape after the pump tests. The combined PROFILE and cleaning tool showed no defects on the gauge plates. The magnets of the tool collected a small amount of ferromagnetic material. All discs of all tools showed only small abrasion effects. No damage could be detected by any part of the GEO or MFL tool.

The GEO tool showed good results. The bends and the difference in diameter of different pipes due to fabrication tolerances were clearly detected. All artificial defects except two in the straight pipe were detected by the MFL tool. Only the smallest defects having a diameter of 7mm and depth of 10 and 30% were not detected.

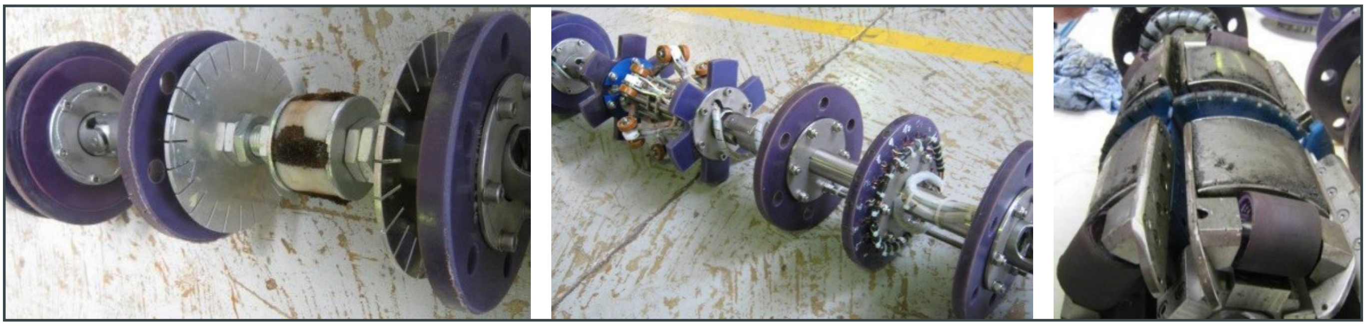


Figure 7: PROFILE tool (left), GEO tool (middle) and MFL (right) after pump test

Figure 8: Vertical launching of PROFILE tool

The tools showed excellent repeatability. There was no difference in the good quality of data in the end of the test compared to the data collected directly after starting the tool. After completion of the evaluation phase, the tools were mobilized.

"A joint development project proved to be the right way to get appropriate inspection results and to ensure a safe operation.
Olivier Gillieron

INSPECTION EXPERIENCES

Inspection execution

As for any ILI operation, the preparation phase is a key phase. If inspection objectives have been clearly set and communicated and engineering phase have been made (tool design, development and evaluation), others tasks must also be completed prior to execution.

They are typically (but not limited to): definition of the task matrix, preparation of operation planning, preparation of operating and communication procedures, preparation of contingency plans, safety, verification of pipeline operating conditions, logistic, etc…

The operational pigging sequence was also defined in an early stage. It has driven tool design as described in section "Tool design" It follows an iterative process:

- The PROFILE tool which has the objectives to make the final cleaning and to check the minimal pipeline diameter (VS minimal diameter of the next tool),
- The GEO tool's objectives are to measure the internal pipeline diameter and to give a statement about the position of any pipeline reduction or bend position
- The MFL tool which has the objectives to detect and to size internal and external metal loss

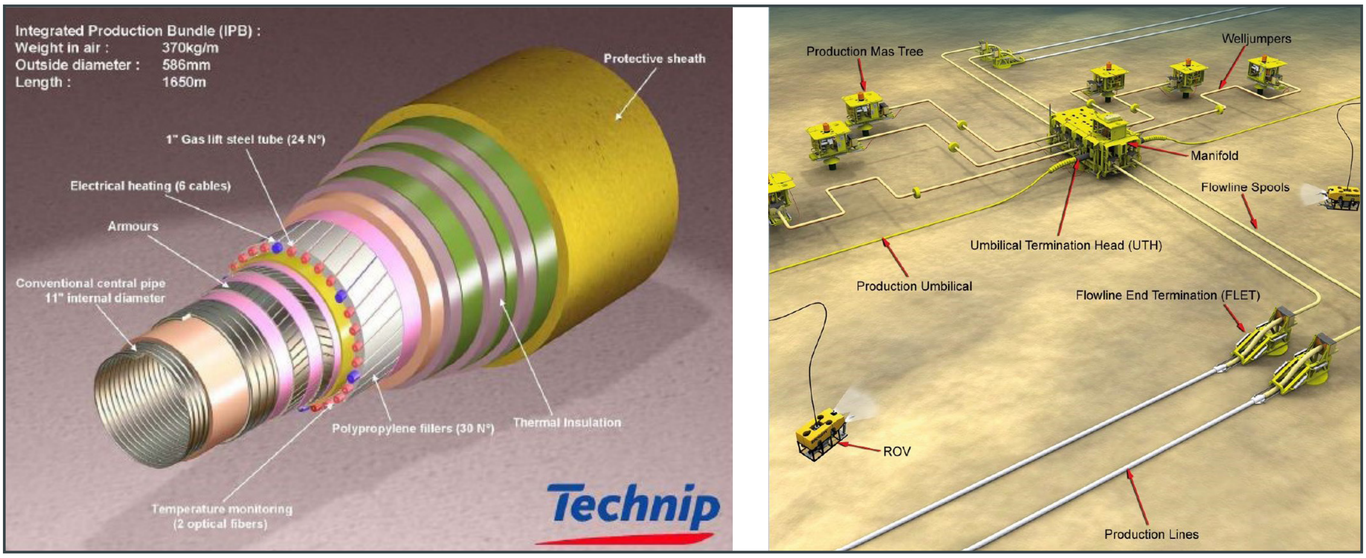


Figure 9: Sketches representing the production loop configuration of the case study

This operational sequence has been used on Total E&P deep offshore pipelines until now and remains the standard sequence today.

More than 12 pipelines have been inspected by ILI until now, not without difficulty. Issues can be divided into two classes:

- Operational issues: accumulation of debris and/or deposit (sand, hard deposit, etc…) can be detrimental to ILI performances, and can even be catastrophic. Cleaning pig must be enough efficient to remove those debris but the most important aspect is its capacity to push debris up through the 500+m riser. Some metallic debris coming from broken choke valve internal valves have been also encountered.
- Tool related issues: the same kind of difficulties as standard pipelines has been encountered in the first runs, with the difference that pigs have to support more constraining conditions. They are mechanical damages (PU wheels damage for example), ILI tools damage (sensor damage, electronic malfunction) and ILI data quality degradation / data loss. Technical improvements have been made to address those constraints.

Inspection results and lessons learned

More than 12 pipelines have been inspected by ILI from 2012. They have been beneficial for many aspects.

We propose to present a case study which is representative of the added value of ILI. It corresponds to the first ILI of a production loop which the following characteristics:

- 12" production loop
- Riser comprised of flexible riser, IPB (Integrated Production Bundle) technology
- Material of rigid sections: API 5L X65
- Pipe type of rigid sections: PiP with seamless inner pipe
- Overall length of about 14km
- Nominal Wall Thickness (NWT) of rigid sections: 17.5mm
- Maximum Operating Pressure (MOP) of more than 300 bar

Same pig sequence as presented in section "Inspection execution" was followed. Even if cleaning issues were encountered, GEO tool and MFL tool data quality (velocity, magnetization for MFL) was not questionable.

As shown in Figure 10, a large number of indications were reported, several internal metal loss features were identified with high depth, the most critical features being located in spools or bends.

Several investigations were launched in order to directly or indirectly cross-check ILI results:

- Flooded Member Detection (FMD) on PiP sections to check whether flooded or not
- Non-intrusive electromagnetic based technique for verifying corrosion on spools
- And finally, due to the severity of ILI results and to uncertainties on the above investigations results, it was decided to change two spools from which a section was recovered for verification 3D laser scanning
- .

Figure 11 shows pictures of recovered spool and 3D scan image. Based on those results, main conclusions and way forward are:

- ID/OD discrimination sensors have allowed the detection and sizing on bends
- Depth sizing is acceptable, but actual length/width are higher than reported by ILI
- ILI results combined with 3D scanning allows to confirm the corrosion mechanism of this production loop
- Corrosion prevention actions shall be strongly reinforced: inhibition, enhanced pipeline cleaning.

CONCLUSION

As stated above, ILI provides the best complete set of inspection data of a rigid pipeline because it covers almost the full length and circumference of the line. ILI tools now used as standard are Geometry and Metal Loss (MFL and UT) inspection tools with the objectives to detect and to size internal and external metal loss.

The development of ILI tools for deep water pipelines and their application in the last 5 years allow Total E&P to achieve their integrity objectives, i.e. to give good visibility to the integrity status of the pipelines, to verify the efficiency of corrosion prevention actions and to make decisions on repairs and/or operating conditions.

The joint development project proved to be the right way to get appropriate ILI tools covering all aspects attached to a deep sea inspection and to ensure a safe operation without damage to the pipeline.

3P Services and Total E&P continue to gain valuable experience in deep water environment, leading to further tool and operational improvements. Unanticipated issues have arisen and been successfully addressed.

New challenges also beckon: single line/tie-in, ILI in high WT and multi-phase conditions, investigation and

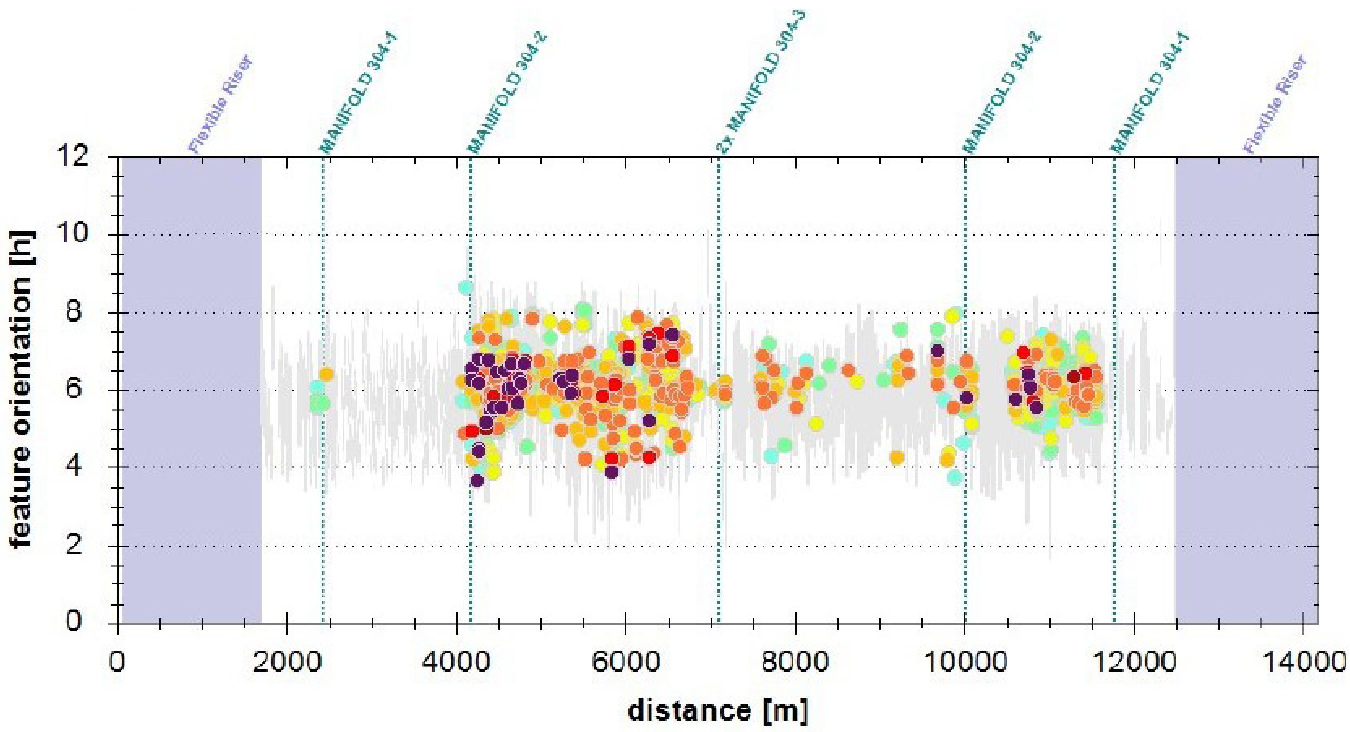


Figure 10: Example of ILI results: metal loss distribution along a production loop

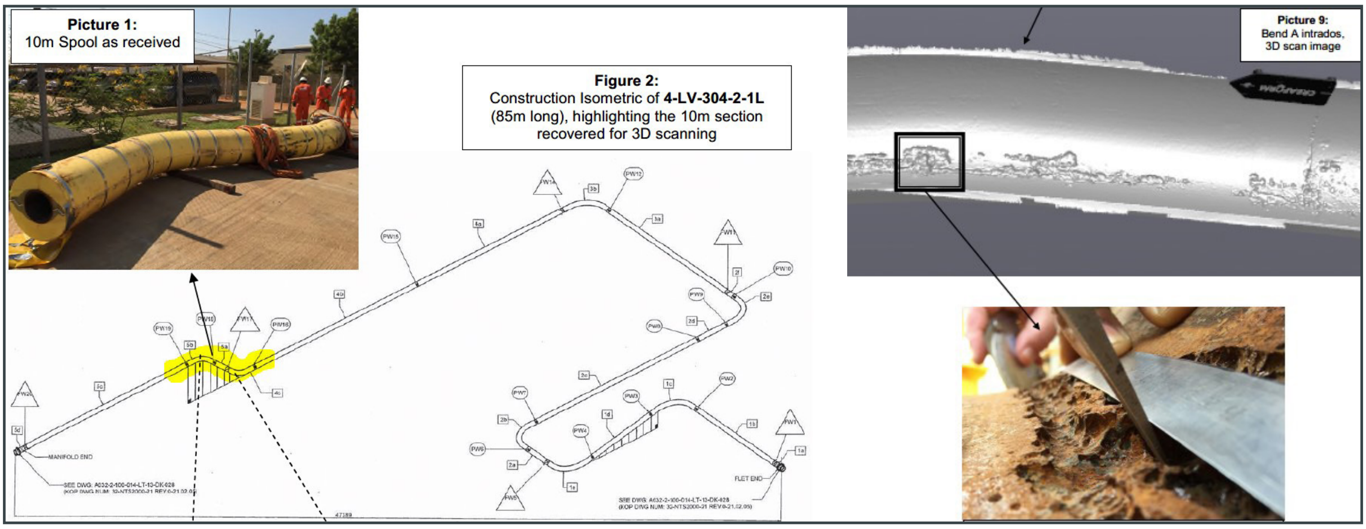


Figure 11: Examples of investigations done after ILI operation

verification of ILI findings in deep water environment, pipeline repair (EPRS) among other. Finally, the authors wish to express their gratitude to Total E&P Angola and TUC Nigeria-DWD affiliates, who are the primary initiators of these developments.

References

[1] "Magnetic Flux Leakage (MFL) Technology For Natural Gas Pipelines Inspection", J.B. Nestleroth, T.A. Bubenik, 1999, National Technical Information Center
[2] "Handbuch Molchtechnik", B. Skerra, 2000, Vulkan-Verlag

Authors

Olivier Gillieron

Total Exploration & Production, France

NDT/Inspection Specialist

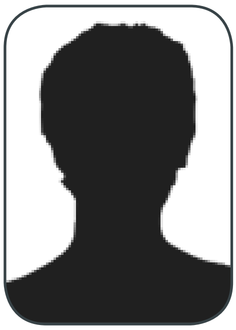
olivier.gillieron@total.com

Humberto Rodriguez

Total Exploration & Production, Angola

Head of Inspection

humberto.rodriguez@total.com



Basil Hostage

3P Services, Germany

Head of Business Development

hostage@3p-services.com

Dr. Daniel Schaper

3P Services, Germany

Head of Research and Development

schaper@3p-services.com

CHALLENGES OF A LARGE OFFSHORE PROJECT FROM A LINE PIPE MANUFACTURERS VIEW

Christian Kassel, Dr. Andreas Liessem; Trond Gjedrem > EUROPIPE; Nord Stream 2 AG

Abstract

The Nord Stream 2 pipeline will transport natural gas into the European Union (EU) to enhance the security of supply, support climate goals and strengthen the internal energy market. Running through the Baltic Sea, Nord Stream 2 will deliver natural gas directly from some of the world's largest known reserves in Russia to the neighbouring EU gas market. The pipeline route starts in Narva Bay (Russia) and travels to a planned landfall close to Lubmin (Germany). Construction of the pipeline is scheduled to commence in 2018, before the pipeline system is commissioned in late 2019.

EUROPIPE was contracted to deliver 1101,5 km of 48 in. dia. line pipe with a wall thickness of 26.8 mm, and 20 km of 48 in. dia. line pipe with a wall thickness of 34.6 mm, including a three layer polyethylene anti-corrosion coating. Along with the delivery of line pipe, EUROPIPE received an order for the production of 95 buckle arrestors and transition pieces with a wall thickness of 34.6 mm, as well as the induction bends for the landfalls in Germany and Russia.

This paper will outline the challenges that EUROPIPE has faced when manufacturing pipe for use on the Nord Stream 2 project maintaining the tough time schedule and stringent quality requirements.

INTRODUCTION

This paper shows the challenges a line pipe manufacturer is faced with on the example of the Nord Stream 2 Project

The Nord Stream 2 pipeline will transport natural gas into the European Union (EU) to enhance the security of supply, support climate goals and strengthen the internal energy market. Running through the Baltic Sea, Nord Stream 2 will deliver natural gas directly from some of the world's largest known reserves in Russia to the neighbouring EU gas market. Figure 1 shows the pipeline route, which starts in Narva Bay (Russia) and runs to a planned landfall close to Lubmin (Germany). Construction of the pipeline is scheduled to commence in 2018, before the pipeline system is commissioned in late 2019.

The two strands, each 1227 km long, 48 in. dia. pipeline making up Nord Stream 2 have wall thicknesses ranging from 26.8 mm - 41 mm. The pipelines have been designed to meet the requirements of the DNV-OS-F101 pipeline design code and the steel pipe materials will, therefore, meet the DNV offshore standard F101, including fracture arrest properties (Suffix F), enhanced dimensional requirements (Suffix D), and requirements for higher utilisation (Suffix U) for pipes with a wall thickness of 26.8 mm.

The new Nord Stream 2 pipelines will generally follow the same route as the two existing Nord Stream pipelines, however the first 100 km of the route through Russian waters is different, see Figure 1. The maximum water depth along the route is approximately 220 m.

With a consistent inner diameter (ID) of 1153 mm, Nord Stream 2 has been designed with three different design pressures, 220 bar, 200 bar and 177.5 bar, which correspond to steel wall thicknesses of 34.6 mm, 30.9 mm and 26.8 mm, respectively. While the most southern section of the pipeline will have a wall thickness of 26.8 mm, the most northern section will have a wall thickness of 34.6 mm. The mid-section will have a wall thickness of 30.9 mm. For the landfalls line pipe with a wall thickness of 41 mm are used. This design means that the steel

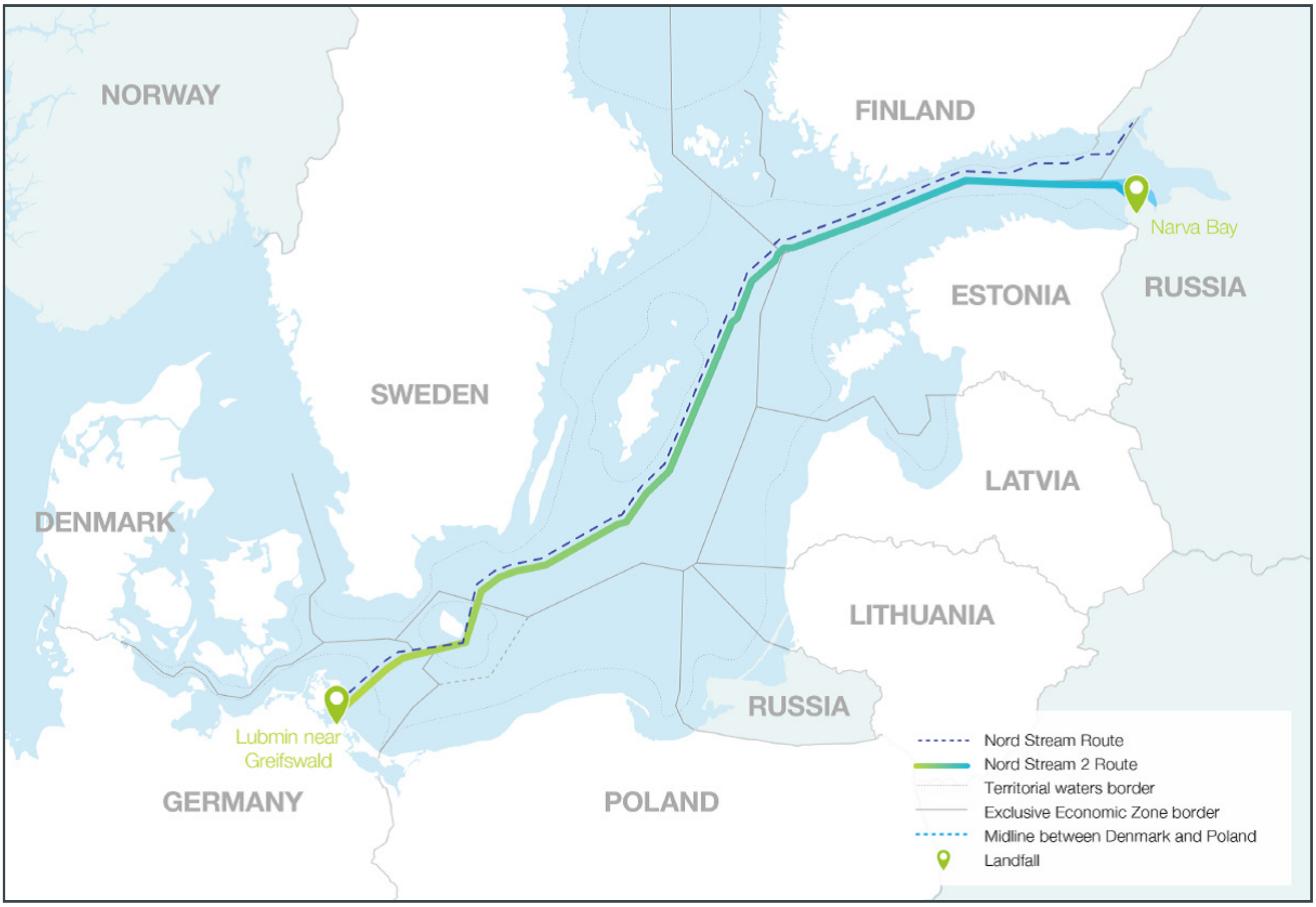


Figure 1: Pipeline Route

weight of the pipe ranges between 780 – 1010 kg/m, amounting to a total steel consumption for one line of approximately 1.1 million t (Table 1).

Total Length of one pipeline	~1,200 km
Diameter	Const. I.D. 1,153 mm
Wall Thickness	26.8/30.9/34.6/41 mm
Weight	780 – 1010 kg/m
Capacity	55 bcm/a (27.5 bcm/a per line)
Planned start of gas deliveries	End 2019
Maximum pressure	220 bar

Table 1: Nord Stream 2 Technical Data

Before the tender for pipes was issued, the Nord Stream 2 project executed a comprehensive and international prequalification program. Interested pipe suppliers who could not prove that they had produced pipes according to the Nord Stream specification recently, but were regarded to have the capability to manage such a challenging job, were invited to prequalify through a trial production. During this trial production, the pipe suppliers were required to produce 20 pipes, all without any defects nor rejections. Only pipe suppliers who managed this hurdle would be prequalified to participate in the tender. This tender was amongst the largest ever in the pipeline industry, covering a total supply of 2.2 million tons of high quality offshore steel pipe.

A number of pipe suppliers in Asia, Europe and America participated in the program, with most companies completing it successfully. The tender was consequently issued to seven prequalified bidders in August 2015, before the supply was awarded to three successful pipe suppliers – Russia's Chelpipe and OMK and Germany's EUROPIPE GmbH (EUROPIPE) – in March 2016. The decision to award the contract to three suppliers was made by Nord Stream 2 due to the high quantities that needed to be supplied for the project within a relatively short period of time (2500 km over a 22 month period, equating to over 110 km per month).

EUROPIPE was contracted to deliver 1101,5 km of 48 in. dia. line pipe with a wall thickness of 26.8 mm, and 20 km of 48 in. dia. line pipe with a wall thickness of 34.6 mm, including a three layer polyethylene anti-corrosion coating. The company's pipes are produced in the UOE mill of EUROPIPE and coated at MÜLHEIM PIPECOATINGS (MPC). Along with the delivery of line pipe, EUROPIPE received an order for the production of 95 buckle arrestors and 8 transition pieces with a wall thickness of 34.6 mm, as well as 62 induction bends for the landfalls in Germany and Russia. Europipe plans to manufacture its share of Nord Stream 2 pipes with lots per month of up to 90 km. Several factors must be considered and solved when working as part of a project of this scale. This article will outline the challenges that EUROPIPE has faced when manufacturing pipe for use on the Nord Stream 2 project. When combined, these considerations entail a tough project, particularly with demanding time constraints and high quality requirements.

CHALLENGES

Manufacturing procedure qualification tests

After being awarded the contract, but prior to the start of mass production, a comprehensive qualification program, or manufacturing procedure qualification test (MPQT) had to be performed in the plate mills, pipe mill and coating yard.

The purpose of a MPQT is to fine-tune the manufacturing process and test all parameters to assure that the mass production is stable and consistent. Due to the tough time schedule of the project, the qualification program had to be performed in a relatively short time.

The scope of the MPQT for the Nord Stream 2 project included the manufacture of 20 pipes per steel plate route and intensive testing of the mechanical properties. An equivalent qualification program also had to be conducted for the buckle arrestors and induction bends.

Line pipe

The line pipe material supplied for the Nord Stream 2 project has to be produced in accordance with the project's specification, which is based on DNV's offshore standard, DNV-OS-F101. For most of the EUROPIPE delivery, the SAWL 485 FDU material grade is required. In order to fulfil the requirements of the Nord Stream 2 project in terms of nondestructive testing and geometry, as well as the combination of large diameter, heavy wall and constant ID, the processes of plate and pipe manufacture needs a high degree of robustness.

Furthermore, the production of such line pipe material takes place in the area of conflict of several dissimilar properties, including weldability, toughness, strength and deformability, weld seam and heat affected zone (HAZ) toughness, corrosion resistance, and pipe geometry. While dissimilar, these properties interact.

For the weldability of pipes, engineers ask for low carbon equivalents (CE). However, they also require high strength and a low yield to tensile ratio. The toughness requirements, Charpy V-notch toughness (CVN; 50 J at -20°C) and drop weight tear (DWT; 85 % shear area at -10°C), interact strongly. Low carbon steels exhibit excellent CVN toughness with limited DWT shear area ratios. HAZ toughness may be achieved by expensive alloying approaches, yet, these are quite often in conflict with the DWT properties and low CE. An additional requirement for pipes with a wall thickness of 26.8 mm is the supplementary requirement ‘U’ in accordance with DNV-OS-F101. For the Nord Stream 2 project, a control mechanism for Suffix U (a so-called ‘comfort zone’) was introduced.

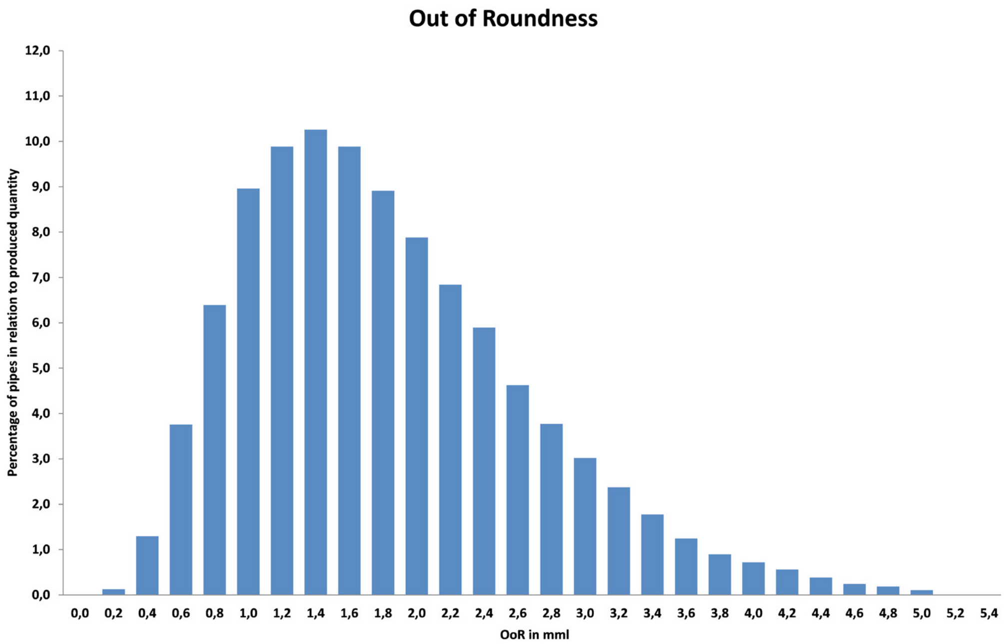


Figure 3: Out of Roundness Pipe Ends

Reported on a weekly basis, the comfort zone is calculated as follows:

Comfort zone = average yield strength - 2 x standard deviation - specified minimum yield strength

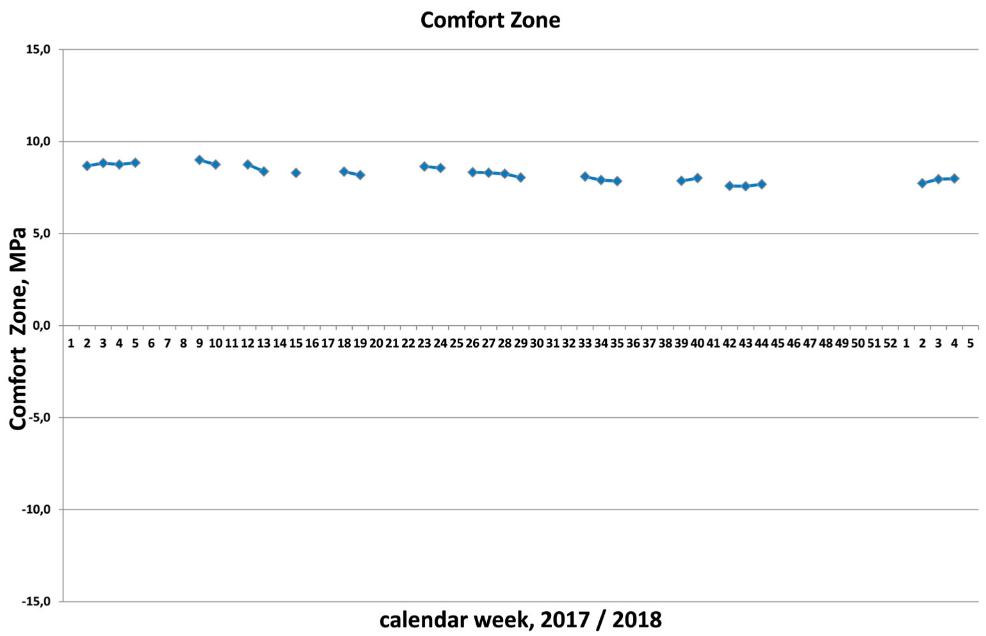


Figure 2: SR “U”, Comfort Zone

The results to date are in a range of 5 - 10 MPa, which shows that the Suffix U requirement is safely met (Figure 2).

Geometrical requirements also need to be met for the Nord Stream 2 project. Based on the positive results obtained during construction of Nord Stream in 2010 - 2012, a stringent out-of-roundness (OoR) requirement was specified by Nord Stream 2. OoR needs to be kept within very tight limits to assure that no time is lost for pipe fit-up prior to offshore welding during construction. OoR of the pipe ends was specified to a maximum of 5.0 mm but with the additional limitation that at least 50% of the pipe ends should show an OoR of 3.0 mm or less. Pipe suppliers were required to measure these values with automatic high resolution laser systems or similar, which have an accuracy of approximately 0.2 mm. They are significantly more reliable than manual measurements. Measuring OoR manually is not regarded sufficiently accurate. Due to the investments that EUROPIPE has recently made, this challenge can also be fulfilled safely (Figure 3).

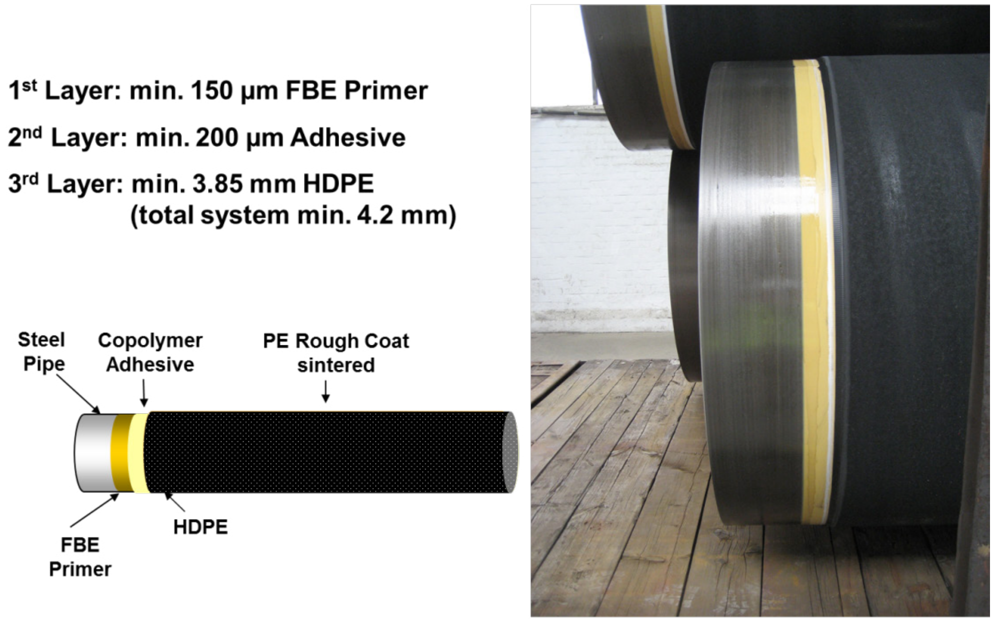


Figure 4: Structure of 3-Layer HDPE Coating

Since a low OoR is regarded as a prerequisite to allow for fast offshore welding, it is therefore an important factor for meeting an overall project schedule. All parameters from the running production are stable and safely within the Nord Stream 2 specification requirements.

Coating

Offshore pipeline conditions can often be considered extreme and pipelines require effective long term protection against corrosion attack from seawater and aggressive chemical and microbiological agents on the seabed (soil). In-service conditions require a design temperature in the range of -10°C to +40°C. However, during pipe transport and storage prior to installation, lower temperatures of down to -40°C can occur.

A three layer high density polyethylene coating (HDPE) was selected for the Nord Stream 2 project. This coating is characterised by high mechanical resistance in terms of impact and hardness, suitability at low temperatures in terms of impact, high flexibility, UV and heat resistance, as well as effective adhesion to steel. It has low water absorption, a high electric resistivity and forms a good barrier against corrosive media. Figure 4 shows the basic structure of the coating system.

The minimum total coating thickness is 4.2 mm (FBE primer minimum 150 µm). To enhance adhesion to the concrete weight coating, the top coat was designed with sintered PE powder applied on top of the PE layer, the so-called 'rough coat.' The 3LPE coating is applied in line with the ISO21809-1 rev. 10-2011 as a governing standard as well as the specification of Nord Stream 2. For girth welding and non-destructive girth weld testing the cut back at the pipe ends was fixed to 240 mm ±10 mm for PE free and 190 mm ±10mm for the bare steel (Figure 5).

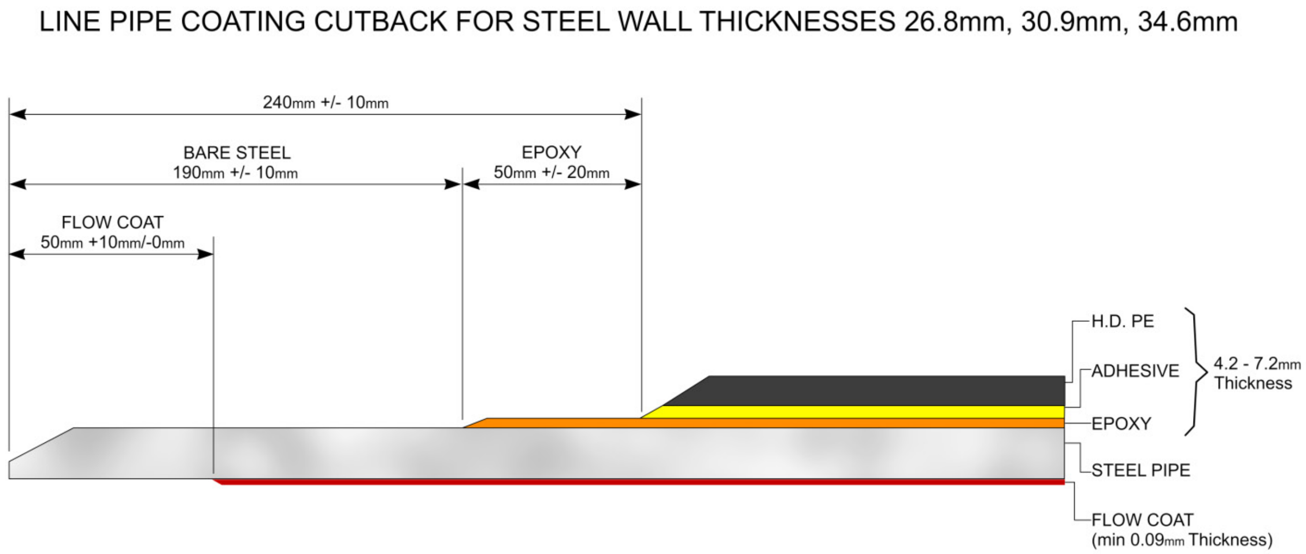


Figure 5: Definition of Cut Back

The tapering angle of the coating is less than 20°. The pipe ends remain unprotected, no varnish is applied, as the comparison of pipe ends with and without varnish showed no significant difference after nine months of storage outside in seaside proximity. It was found that a uniform dense layer of oxides has formed on the pipe ends without varnish. It is expected that the pipes will be stored less than three years from manufacture until they are installed.

To improve flow conditions during gas transport, an epoxy flow coat with a very smooth surface is internally applied. Beside its primary task of reducing hydraulic friction, it also has a function as temporary corrosion protection during pipe transport, storage and installation. For this lining, the governing standard is API RP 5L2 and the Nord Stream 2 specification. The minimum required dry thickness of the internal coating is 90 μm. The cut back length for the lining was defined to 50 mm -0/+10 mm.

The roughness of the finished coating is specified to be Rz ≤4 μm (individual readings) and in average it shall not exceed 3 μm. Only flow coat materials with a high solid content were qualified for the project because it provides lower roughness of the finished epoxy flow coat and has a reduced fraction of volatile organic compounds that is beneficial for HSE-aspects. Figure 6 shows the actual roughness of internally coated pipes based on 22 785 measurements, the average coating roughness value is actually Rz <2 μm.

The tight time schedule of the project was a tough challenge. To increase the production rate while ensuring the required cleanliness of the pipe surface prior to the coating application, the coating line was upgraded for the project. This allowed MPC to coat up to 500 pipes per day internally and externally in a three shift operation.

BUCKLE ARRESTORS AND TRANSITION PIECES

In order to avoid buckling during the laying process buckle arrestors every 920 m have to be included during pipe lay. For the NSP2 project buckle arrestors (BA) and transition pieces (TP) in a one-piece construction are used. EUROPIPES scope of supply are 95 BAs and 8 TPs with a wall thickness of 34.6 mm.

These parts were taken from the routine production and machined on both ends to a wall thickness of 26.8 mm. The TPs are machined on one side only to a wall thickness of 31.9 mm. Challenging requirements on the BA and TP ends were the tight wall thickness range, the Out of Roundness of max. 3 mm and the surface condition of the machined end which was specified with a roughness of Ra ≤ 12.5 μm.

INDUCTION BENDS

For the construction of the landfalls in Russia and Germany induction bends with ID 1.153 x WT 43,0 mm, ID 904,6 x WT 35,5 mm and ID 645,0 x WT 33,5 mm are needed. The material grade is L485 corresponding to the line pipe material grade. Due to the low temperature requirement, the bends have to fulfill the toughness requirement at a test temperature of -48 °C, the bends are delivered in the quenched and tempered condition. In order to maintain a smooth gas flow the induction bends are internally coated.

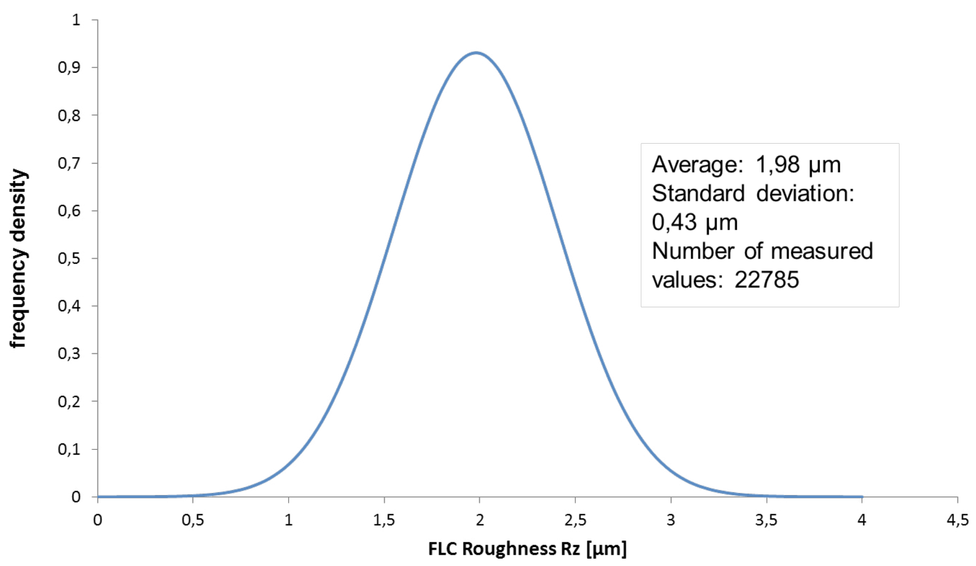


Figure 6: Roughness Rz of coated internal pipe surface

LOGISTICS

In order to maintain the ambitious time schedule of the Nord Stream 2 project, a very tight delivery schedule was implemented. For transport in Germany, from Mülheim to Mukran, trains are the most suitable medium. So-called 'supertrains' with 148 pipes on 37 railcars were used by EUROPIPE for transport in Germany. The delivery of pipes from Mülheim to Mukran started on 25 October 2016. Since this date, each week, an average of 15 km of pipes (or approximately 1250 pipes) have been transported to the storage yard. The maximum quantity that sometimes needs to be shipped is close to 2100 pipes per week. The small quantity of pipe with a wall thickness of 34.6 mm will be shipped to Kotka (Finland), after being transported by train to the port of Bremen from where the pipe will be transported via vessel to Kotka.

PIPE TRACKING SYSTEM (PTS)

All production data, beginning from steel casting up to the finished product, have to be imported to the PTS maintained by NSP2. In addition to the production data, the results of the mechanical testing, chemical analysis and geometrical checks are to be transferred to the PTS. This allows an excellent traceability for the project and fulfills the needs for the pipe integrity management later on. For the line pipe mass production the existing data infrastructure was adapted, so that the data could be send automatically to the pipe tracking system. The experience made during recent projects could be used for this project, but, as the PTS requirements vary from project to project, Europipe would encourage an industry standardization of PTS requirements.

For a mass production the data to be reported could be extracted from the EUROPIPE in-house Production Information System (PRODIS). However for the small scale production of the other products like BAs, TPs and induction bends the feeding of the PTS is done manually via uploading the relevant data.

PROJECT MANAGEMENT

This large project could not be processed like a routine order. In order to manage this extensive project a specific project management structure had to be build up in order to ensure that the involved disciplines are working together project focused. Beneath technical and commercial assignments the document management became very important. Up to now 173 documents are issued (a.o. 18 ITP, 18 x MPS, 27 Reports (e.g. MPQT), 17 Procedures, …). All these documents had to be followed up from issuing the first revision up to the final approval which had to be achieved in due time in order to maintain the tough time schedule.. This process had to be strongly managed as several companies (NSP2, DNV GL, GLIS) were involved in the approval process.

CONCLUSIONS

The extension of the existing Nord Stream pipeline system with another two pipelines of 1227 km in length is one of the largest and most important infrastructure projects for western European gas supply. Nord Stream 2 will transport up to 55 billion m3 of natural gas into the EU annually. EUROPIPE has a significant share in the market of large diameter pipe and is able to handle large projects. Approximately 45% of Nord Stream 2's pipe quantities have been awarded the company.

The Nord Stream 2 pipeline project shows how companies can overcome both technical and logistical challenges. Due to the significance of the project, the technical requirements and consistent quality of the steel pipes are of paramount importance. This applies to mechanical properties, geometrical tolerances and to the extent of pipe testing during manufacturing. To produce the pipes in accordance with the DNV offshore standard and the Nord Stream 2 project specification, a high degree of process robustness has been necessary but challenging. The logistics chain of pipes from EUROPIPE will include train transport in Germany and vessel shipment to Finland. At the end of the order, nearly 91 000 pipes will have been transported by EUROPIPE to the final destinations in total.

Authors

Christian Kassel

EUROPIPE GmbH

Senior Manager Technical Management – Inquiries

christian.kassel@europipe.com

Dr. Andreas Liessem

EUROPIPE GmbH

Managing Director

andreas.liessem@europipe.com

Trond Gjedrem

Nord Stream 2 AG

Engineering Manager

trond.gjedrem@nord-stream.com

NOVEL COST-EFFECTIVE APPROACH LEADING TO SUCCESSFUL SAFE ISOLATION AND DECOMMISSIONING OF OFFSHORE SOUR GAS PIPELINES

Pooya Gholami, Hadi Tabassomi, Mahdi Nouri > IPEC, Pipeline and Process Services

Abstract

Safety is a crucial issue in operational activities. When performing a hot work operation on a live pipeline, it is very important to isolate the pipeline to prevent any dangerous event. In this paper, a newly and innovatively designed approach has been presented which has been used to isolate a 32" and an 18" offshore and infield pipelines from sour gas and prepare them for hot work operation in order to substitute a T-piece with a pipe piece on the line.

The pipelines had been depressurized, but still filled with inflammable sour gas and not ready for hot work operation. In this designed approach, injection of Nitrogen as inert gas, launching pigs for batching the mediums, injecting MEG (Mono Ethylene Glycol) for washing out the remained condensed gas on inner pipe wall and finally usage of Medium Expansion AFFF foams have been implemented in order to prevent diffusion of inflammable gases and prepare a safe condition on the pipelines.

The implemented procedure resulted in a well-attained and fully safe condition which had an LEL and H2S amount of zero. The hot work operation, which included cutting a T-piece and welding a pipe piece instead, was performed safely and completed successfully.

This remarkable result in safe isolation of pipelines by using the implemented method was practically achieved with not a considerably high cost and a very low required time for preparation of equipment.

INTRODUCTION

Isolation of pipelines and pipework systems is a key requirement for the maintenance and safe modification of oil, gas and petrochemical infrastructure. As the aspect of safety, it is important to isolate the gas containing pipelines before performing any hot work operation on the pipeline. The isolation process is also known in industry as "lock-out / Tag-out" and is used to isolate machinery and equipment from its energy source, and acts as an alternative to inert purging (depressurizing and water filling) and intrusive isolation techniques [1]. It is important to ensure the isolation of any unsafe machinery/equipment from potential uncontrolled energy sources during repair, service or maintenance work.

Common Isolation Methods and Experiences

Some reputable companies have pre-determined and standard approaches towards isolation operations. Chevron Pipeline Company, for instance, presents a standard to ensure that isolation of hazardous energy and/or opening of equipment is performed in a safe and controlled manner [2]. In this document, Chevron has presented the requirements, instructions, records and all the information required for performing a safe isolation operation.

Henning Bø at T.D. Williamson [1] has discussed different case studies where non-intrusive inline isolation tools facilitated offshore decommissioning activities. They provided inline, double block and monitor (DBM) pipeline isolation services, using two SmartPlug tools to isolate the different size pipeline at subsea set locations upstream and downstream of the platform in North Sea and Gulf of Mexico. The tools were tracked and operated in the pipeline using wireless through-wall Smart Track communication systems. Upon completion of the tie-in, the isolation tools were unset and the entire set up of isolation tools, batching pigs, and welding pigs was pigged to the pipeline terminal onshore and successfully retrieved. The following picture shows the tool which had been used in different sizes.

There are multiple companies that also utilize the plug technology for pipeline isolation. It means that this method is well-known and popular technique in this industry.

> *"When performing a pipeline isolation operation, planning is the key feature towards excellent performance of the job.*
> *Pooya Gholami*

In addition to that, some other companies add some alterations to this technology in order to enhance its application. PLIDCO uses a Shear+Plug method for pipeline isolation [3]. The PLIDCO Shear+Plug is a hybrid tool that uses the power of hydraulics to cleanly shear through the pipeline and valving mechanism - providing a positive metal-to-metal seal. The Shear+Plug machinery, tools and process are heavy duty. They are built and installed like any permanent fixture to the pipeline system. The system features a permanent metal-to-metal line seal that is welded to the pipeline which assures safety and long-term stability of the line isolation. Installing Shear+Plug is like assembling a gate valve into the line piece by piece. Because there is no tapping required, no metal shavings can enter the line to cause contamination or damage. Instead, the hydraulic shear drives the flattened coupon into a receptacle below the pipeline - there is no possibility of it falling into the line and having to be retrieved. On the other hand, J. Aleksandersen et al. [4] implement a remotely controlled and operated (umbilical-less) pipeline isolation system for use on oil and gas pipelines in all dimensions. These systems are designed, manufactured, and tested to isolate high pipeline operating pressures. Communication with the tool for typical subsea application is done from a surface vessel, via acoustic signals to a subsea module, then through the pipeline wall via Extremely Low Frequency (ELF) electromagnetic waves. All critical parameters such as pressures and temperatures are monitored. The tool design is fail safe, i.e., as long as there is a differential pressure over the isolation system it cannot unset. Thus any failure to the control system will not jeopardize its operation.

The importance of an appropriate isolation operation is so vital that it goes without saying that if a proper isolation method is not implemented during pipeline repair work, dangerous incidences might occur. As stated in a case study by Process and Engineering Group [5],

Figure 1: TDW Double independent seal SmartPlug® train with third seal for hydrotesting [1]

there was a fatal flash fire at one of the crude oil pipeline terminal, during pipeline repair works. The incident happened during edge preparation i.e. grinding on the open end (plugged with bentonite clay) of a 42" NB pipe. In this case, the isolation of the crude oil header was done by a mud plug using 'Bentonite Clay' at the open end of the 42" pipeline. After mud plugging, the plan was to weld the newly fabricated spool piece after necessary grinding, edge preparation & fit-up. But, the incident happened during joint fit-up operation (grinding etc.), for welding of the newly fabricated spool piece with the open end of existing pipeline. The cause of flash fire incident was due to release of residual hydrocarbon vapors from the line on account of dislodgment (partly or fully) of the Bentonite Plug.

New Isolation Technologies

There is a wide range of pipeline isolation techniques some of which are described here. The operators often need to assess the optimum solution for their pipeline isolation challenges.

The Stats Group [6] presents a couple of techniques for safe isolation of pipeline for hot tapping and other purposes. Some of these methods are described as follows.

- **Non-Intrusive Inline Isolation**
  The Plug technology provides fail-safe double block and bleed isolation of pressurized pipelines while the system remains live and at operating pressure. Dual seals provide a zero-energy zone to enable maintenance work on pressurized systems to be carried out safely and efficiently. Piggable isolation tools require no welding or cutting into live lines, leaving no residual fittings or hardware on the pipeline. This feature ensures pipeline integrity is maintained and it is always recoverable upon job completion. The application of this technology includes: Pipeline valve replacement / repair, Riser replacement / repair, Mid-line pipeline repair / tie-in, Platform abandonment and bypass and Pipeline diversion. This technology is shown in figure 2.

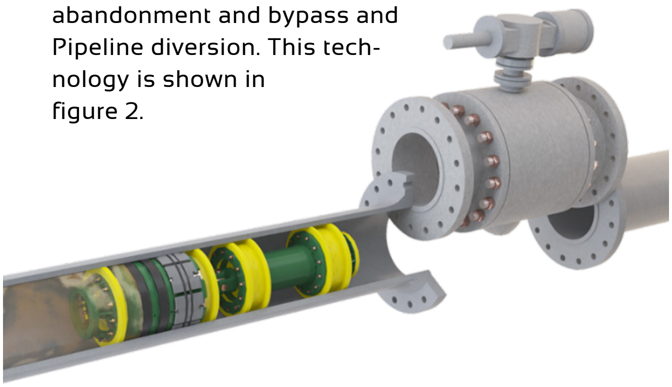


Figure 2: Plug technology [6]

- **Hot Tapping and Plugging**
  Hot Tapping and Plugging can be achieved using the DNV-GL type approved BISEP [6]. This patent provides fail-safe double block and bleed isolation deployed through a single full bore hot tap penetration, without the need for additional bleed or vent ports. It offers significant safety advantages over traditional line stop technology, the hydraulically activated dual seals provide leak-tight isolation of live pressurized pipelines.

  This high integrity isolation is provided by a spherical dual seal plug which is deployed from a pressure competent launcher through an isolation valve and rotated towards the flow of pressure to be isolated. The seals are activated by a hydraulic cylinder inside the plug which compresses the seals, the resultant radial expansion pushes the seals out against the pipe bore. Further application of hydraulic pressure generates a rubber pressure in the seal elements which allows the annulus void between the seals to be pressure tested. Each seal is independently tested with full pipeline pressure in the correct direction to verify leak-tight isolation. The seal annulus void is vented to ambient through the BISEP™ plugging head to provide a zero-energy zone and provides constant monitoring capabilities to prove the seal integrity before and during maintenance, repair, or modification activities. Line pressure acting against the tool pressure head maintains seal pressure creating a fail-safe feature providing actuation independent of the hydraulic system. The ejection load resistance is provided by the BISEP™ deployment head. This technology is schematically illustrated in figure 3.

- **Small Bore Hot Tapping and Plugging**
  The patented BI-STOP™ [6] provides a unique hot tap and plugging system to address challenges with small-bore pipework that have absent or limited

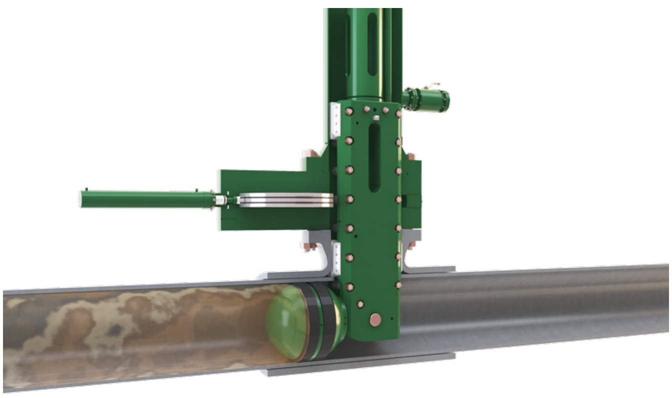


Figure 3: BISEP technology [6]

isolation facilities. This cost-effective solution enables small bore pipework to be isolated, cut and if required, terminated with a full-bore valve whilst the system remains live. The BI-STOP™ allows maintenance or remediation activities to be carried out safely, eliminating the need for a system shutdown. This technology has been shown in figure 4.

- **Tie-In Clamp**
  Mechanical Tie-In Clamps facilitate the connection of new branch pipework to existing infrastructure without the requirement for welding. Tie-In Clamps are routinely used to provide a flanged off-take to enable hot or cold tapping into an existing pipe. The system components are compatible with a wide range of fluid types and flow conditions and are designed for ease of installation with minimal disruption to the pipework or system to which they are fitted. Figure 5 demonstrates a schematic and operational picture of this clamp.

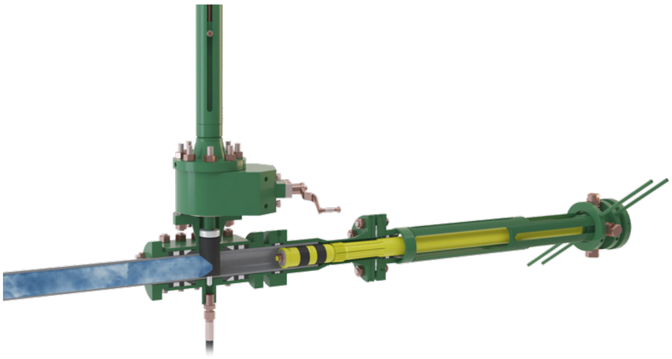


Figure 4: BI-STOP technology [6]

PROJECT OVERVIEW

This paper summarizes the approaches and activities during a non-intrusive isolation operation in South Pars Gas Field platforms.

Purpose of Isolation Operation

There is a T-piece installed on the 32" pipeline and a T-piece installed on the 18" pipeline at platform. These two T-pieces are connected to each other through an 18" pipe with two valves in order to create a bypass route for the gas which connects the two 18" and 32" pipelines through 18" piping and valves. The drawings of mentioned bypass piping and T-pieces are shown in figure 6.

Purpose of the isolation operation under investigation of this paper is to provide a safe condition for removing the two mentioned T-pieces and bypass route.

Figure 5: Tie-in clamp [6]

Pipelines Details and Location

The two pipelines on which isolation operation has been performed and presented in this paper are two offshore pipelines in South Pars Gas Field. The pipelines characteristics are summarized in Table 1.

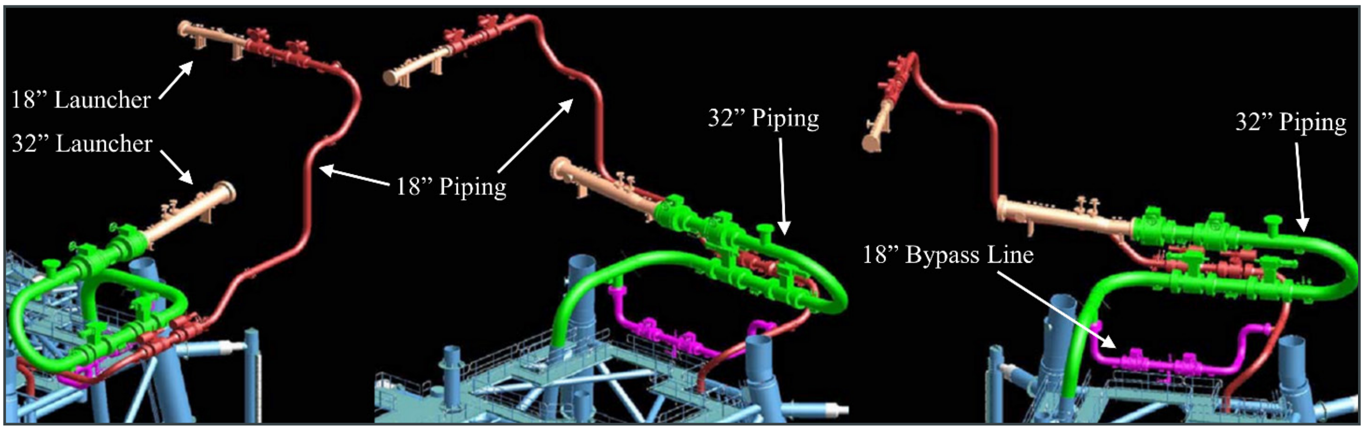


Figure 6: 32" & 18" pig launcher and 18" bypass pipe (Green: 32" pipeline, Red: 18" pipeline, Purple: 18" bypass line) [14]

Nominal Diameter (in)	Length (m)	Outside Diameter (mm)	Wall Thickness (mm)	Internal Diameter (mm)	Volume per Meter (m^3)
32 ″	113458	829.2	28.8	771.6	0.4676
18 ″	5000	457	15.9	425.2	0.1420

Table 1: Pipelines Characteristics [14]

The 18″ pipeline is an infield flow line which transports the reservoir fluid produced from satellite platform to the inlet facilities of the main platform. The 32″ pipeline is an export pipeline which is installed to transport the offshore production from main platform to the onshore plant. Figure 7 shows a schematic diagram of the pipelines and platforms and their locations.

PRELIMINARY ACTIVITIES AND PREPARATIONS

When performing a pipeline isolation operation, planning is a key feature towards excellent performance of the job. Optimum planning calls for the job to be planned in good time, possibly from shore, and for the documents to have been received/quality-assured before work begins offshore. Well-defined boundaries must exist for what are regarded as "normal" work operations, so that the boundaries for what production technicians can do without an isolation plan are not stretched [7].

In order to precisely perform the operational activities and adhere to safety requirements, it was needed that complete preliminary activities including designing the suitable approach, material calculation and equipment preparation be done.

Designed Approach

For the purpose of isolating the pipelines, a pre-designed approach was implemented in the field. The details of followed steps are presented as following procedure.

Firstly, the 32″ and 18″ pipelines were depressurized and flared from both sides and the 32″ onshore side P/R valve was closed while opening the path toward the flare for venting. Afterwards, the preparation of equipment on platform will be started and the H2S / LEL for safety of environment will be checked. Then, both 18″ valves on bypass route will be closed along with closing of MOV and ESD valves on 32″ piping at platform.

The operation will be started by injecting Nitrogen into the launcher and venting to the flare in order to make safe condition for opening the launcher.

A 32″ Poly Foam Pig will be loaded into 32″ launcher (Pig No.1) and by opening the MOV and ESD valves on 32″ piping at platform and injecting Nitrogen via pig receiver drain, the pig will be propelled as much as 2500m of 32″ pipeline. At this time, the MOV and ESD valves on 32″ piping at platform will be closed and the launcher will be vented to the flare for safety. A 32″ High Sealing Low Density Foam Pig will be loaded into the 32″ launcher (Pig No.2) by opening the MOV and ESD valves on 32″ piping at platform and injecting Nitrogen via pig receiver drain, the pig will be propelled as much as 2500m of 32″ pipeline. Then, the MOV and ESD valves on 32″ piping at platform will be closed and venting the launcher to the flare for safety will be done. A 32″ Poly

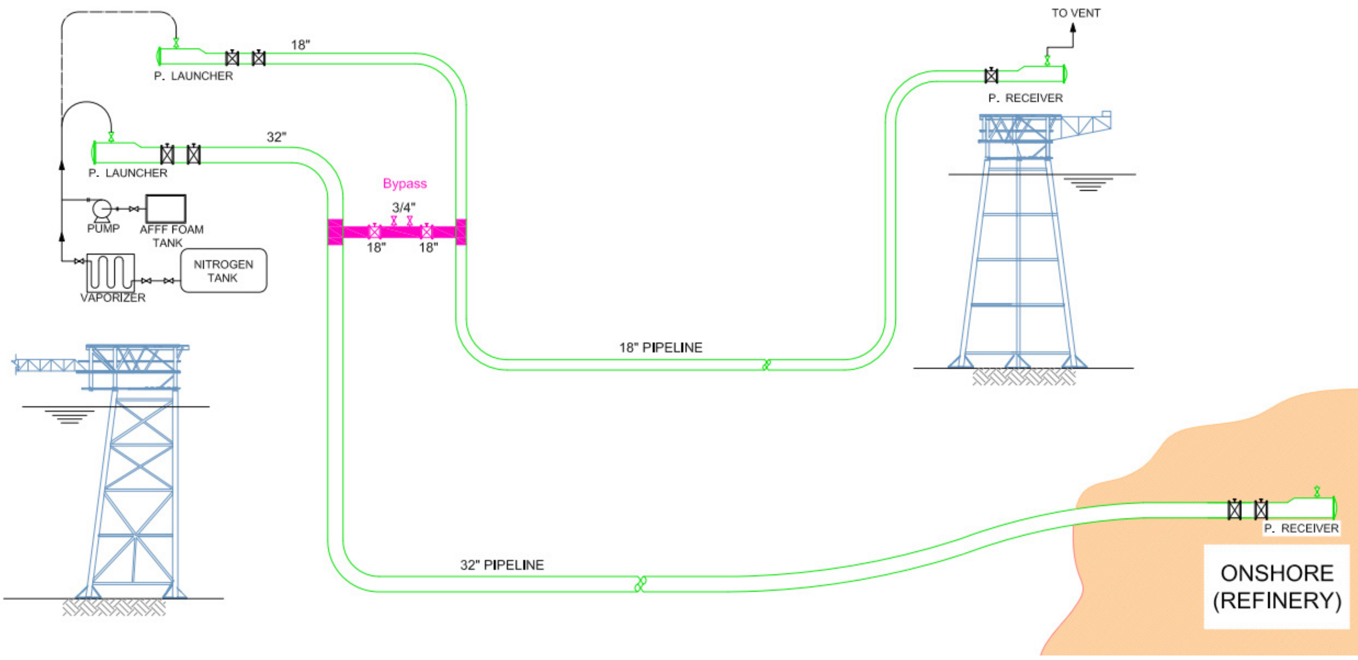


Figure 7: Schematic diagram of the pipelines and platforms and their locations [14]

Foam Pig will be loaded into 32" launcher (Pig No.3) and by opening the MOV and ESD valves on 32" piping at platform and injecting Nitrogen via pig receiver drain, the pig will be propelled only to pass the launcher and valves. Following the launch of Pig No.3, MEG will be pumped for approximately 40m of 32" pipeline (Purpose of MEG injection is to wash the remained gas condensate and clear the pipe wall). After closing the MOV and ESD valves on 32" piping at platform and venting the launcher to the flare, another 32" Poly Foam Pig will be loaded into 32" launcher (Pig No.4) and by opening the MOV and ESD valves on 32" piping at platform and injection of Nitrogen, the Pig No.4 will be propelled only to pass the riser (almost 100m of pipeline). At this stage, expanded AFFF foam will be injected from pig launcher (behind the Pig No.4/Mixed with N2). Finally, the outlet of foam from bypass drain will be checked after opening and checking safe condition in 18" bypass pipeline.

Once the foam is received in bypass drain and the whole riser and launcher are fully filled with expanded foam, the pipeline isolation is completed and removing bypass line can be commenced. Afterwards, cutting operation on T-piece can be started while keeping a low flow of Nitrogen inside the pipeline and around the cutting area.

The same series of activities will be performed for safe isolation of 18" pipeline. However, during the operation on 18" pipeline, flaring from satellite platform will be done continuously to prevent pipeline from being pressurized. This is essential due to low length of the 18" pipeline. Also, since the length of 18" pipeline is only 5km, the second foam pig (Pig No.2) and the 2500m of Nitrogen behind it is omitted from the applicable approach for this pipeline. The final arrangement of this designed approach is illustrated in figure 8.

After safe removal of T-piece and bypass pipe, a same size spool will be fitted and welded instead of the dismantled T-piece. Pigs' recovery will be started with sour gas pressurization from the satellite platform and onshore refinery.

Material Calculation and Properties

The material used for this isolation operation is comprised of: Pigs, Liquid Nitrogen, MEG and AFFF Medium Expansion Foam.

The calculations regarding required material along with the properties of used material are presented in following paragraphs.

Pigs

Usage of pigs in this project is for separation of batches. More than that, it should be considered that the utilized pigs are required to be light enough, so that they would not cause problem during pig recovery with gas which will be performed after completion of isolation and cutting operations. For this reason, poly coated high density foam pigs were considered to be used in this project. Figure 9 shows the utilized pigs in this project.

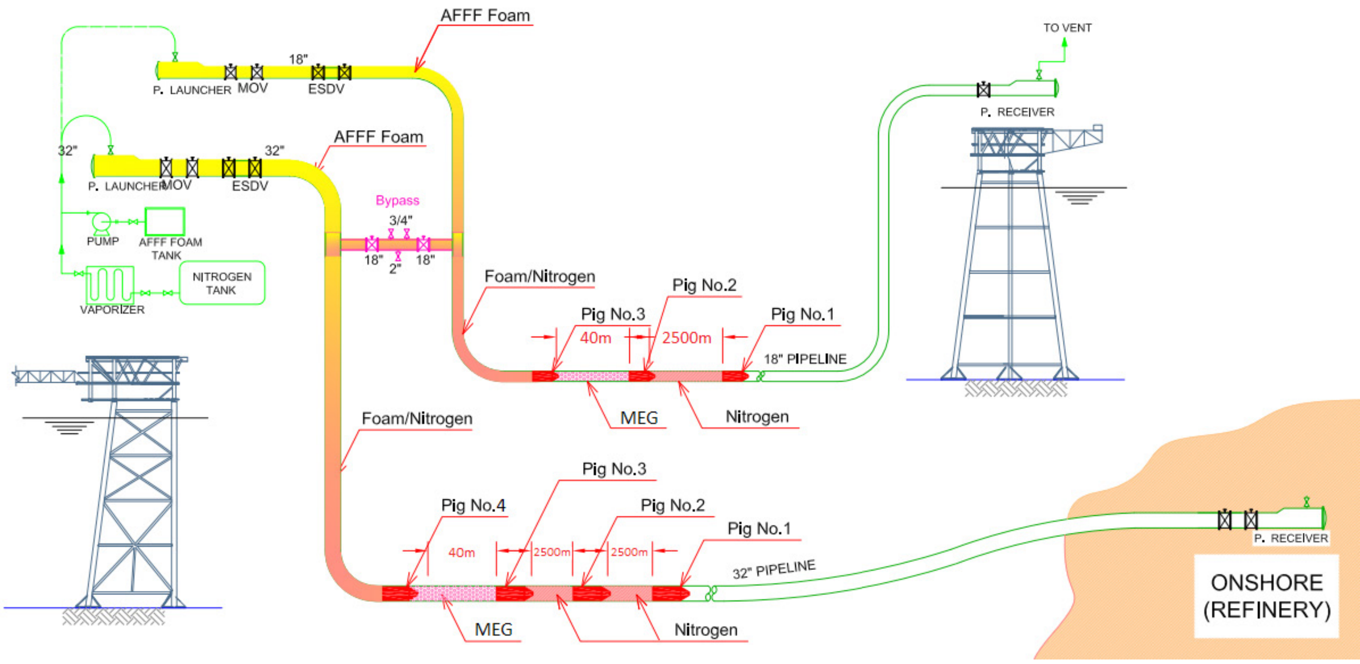


Figure 8: Final arrangement of designed approach [14]

These pigs are not only light-weighted, but also are almost capable of withstanding the penetration of liquids. The only different pig used, was the Pig No.2 in 32" pipeline which was a special low density foam pig with considerably bigger diameter than pipeline inside diameter that has been vacuumed and compressed to fit into the pipeline. Since the 32" pipeline has a high length, and only a small section of it was going to be under isolation operation, this special high-sealing pig was added to the designed approach in order to provide a safer barrier against penetration of sour gas.

Nitrogen

For the purpose of constructing a neutralized condition inside the pipeline, Nitrogen is often being used. In this project, vaporized liquid Nitrogen was considered to perform the job. In order to do so, ISO tanks filled with liquid Nitrogen are needed to be provided and this liquid Nitrogen will be vaporized by means of adequate number of vaporizers. Number of ISO tanks and vaporizers depends on the desired flow rate. The required facilities for this matter are illustrated in figure 10.

The calculations which are used for approximately estimating the location of pig inside the pipeline according to the amount of vaporized and injected Nitrogen are presented as follows [8].

Nitrogen Calculations for 32" Pipeline:

Pipeline Internal Diameter	$ID = 771.6\ mm$
Pipeline Cross Section Area	$A = \frac{\pi}{4} \times ID^2 = 0.4676\ m^2$
Total Nitrogen Mass	$M_{LN} = 2000\ kg$
Contingency Factor of Nitrogen Vaporization	$CF = 1.2$
Actual Mass of Liquid Nitrogen	$M_{LN} = \frac{M_{LN}}{CF} = 1666.667\ kg$
Normal Volume of Gaseous Nitrogen @ STP	$V_N = M_{LN} \times \frac{22.4\ L}{28\ gr} = 1333.33\ m^3$
Temperature Conversion Coefficient	$\alpha_T = \frac{25+273}{0+273} = 1.092$
Pressure Conversion Coefficient	$\alpha_P = \frac{1.2\ bar}{1\ bar} = 1.2$
Actual Volume of Nitrogen	$V_a = V_N \times \frac{\alpha_T}{\alpha_P} = 1212.805\ m^3$
Estimated Location of the Pig	$L = \frac{V_a}{A} = 2593.682\ m$

Figure 9: Left: 32" poly pigs; Right: 18" poly pigs [14]

Nitrogen Calculations for 18" Pipeline:

Pipeline Internal Diameter	$ID = 425.2\ mm$
Pipeline Cross Section Area	$A = \frac{\pi}{4} \times ID^2 = 0.142\ m^2$
Total Nitrogen Mass	$M_{LN} = 1200\ kg$
Contingency Factor of Nitrogen Vaporization	$CF = 1.2$
Actual Mass of Liquid Nitrogen	$M_{LN} = \frac{M_{LN}}{CF} = 1000\ kg$
Normal Volume of Gaseous Nitrogen @ STP	$V_N = M_{LN} \times \frac{22.4\ L}{28\ gr} = 800\ m^3$
Temperature Conversion Coefficient	$\alpha_T = \frac{25+273}{0+273} = 1.092$
Pressure Conversion Coefficient	$\alpha_P = \frac{2.5\ bar}{1\ bar} = 2.5$
Actual Volume of Nitrogen	$V_a = V_N \times \frac{\alpha_T}{\alpha_P} = 349.288\ m^3$
Estimated Location of the Pig	$L = \frac{V_a}{A} = 2459.842\ m$

MEG

Mono Ethylene glycol (MEG) is widely used by the oil and gas markets in wellheads and pipelines to prevent hydrate formation at pipeline conditions. In offshore deep water gas production facilities, where the exposure to lower temperatures in subsea pipelines is common, MEG is used for hydrate inhibition [9]. Hydrate inhibition is achieved by injecting MEG to decrease the hydrate formation temperature below the operating temperature, thereby preventing hydrate blockage of the pipeline. During the gas production process, the lean glycol mixes with the produced water from the formation [10]. Physical properties of Mono Ethylene Glycol can be found in Table 2.

Formula	$C_2H_6O_2$
Molecular Weight, g/mol	62
Boiling Point @ 760 mm Hg, °C (°F)	197 (387)
Vapor Pressure @ 20°C (68°F) mm Hg	0.06
Density, (g/cc) @ 20°C (68°F)	1.115
Density, (g/cc) @ 60°C (140°F) 1.096	1.085
Freezing Point °C (°F)	-13.4 (7.9)
Viscosity, cP @ 25°C (68°F)	16.9
Viscosity, cP @ 60°C (140°F)	5.2

Table 2: Physical Properties of Mono Ethylene Glycol (MEG) [11]

In this project, usage of MEG is considered to wash the pipeline inner wall and clean it from residual hydrocarbon contaminations and condensate liquids which are likely to get vaporized and endanger the safety conditions of the operation. For this purpose, an amount of 40 meters of each pipeline`s length is considered to be filled with MEG. The implemented facilities for injection of MEG into the pipeline are illustrated in figure 11.

The required amount of MEG which corresponds to 40 meters of each pipeline is calculated as per following equations.

MEG Calculations for 32" Pipeline:

Pipeline Internal Diameter	$ID = 771.6\ mm$
Pipeline Cross Section Area	$A = \frac{\pi}{4} \times ID^2 = 0.4676\ m^2$
Total MEG Volume	$M = 40 \times 0.4676 = 18.7\ m^3$

MEG Calculations for 18" Pipeline:

Pipeline Internal Diameter	$ID = 425.2\ mm$
Pipeline Cross Section Area	$A = \frac{\pi}{4} \times ID^2 = 0.142\ m^2$
Total MEG Volume	$M = 40 \times 0.142 = 5.7\ m^3$

Foam

Once all the pigs are launched into the pipeline, there is still a possibility that inflammable gases might penetrate around the pigs and through the batching materials and may come up the riser affecting the safe condition of hot work area. In order to reduce the risk of this probable case, an expanded form of AFFF foam is considered to be exerted into the pipeline. This kind of foam is capable of preventing the penetration of inflammable gases through the area which is covered with the expanded form. The expanded foam is required to fill the pipeline area behind the last pig, through the riser and up to the pig launcher. The chemical to be provided for this purpose needed to function as the below requirements:

- Provide appropriate Expansion Ratio to fill the pipeline in platform and riser area
- Appropriate viscosity to move along pipeline from injection point (launcher) toward piping bends and riser
- Ability to prevent inflammable vapors from passing the expanded foam area and travel from inside the pipeline through cutting area and suppression of condensate gases
- Washing the pipeline inner wall from condensate liquids which produces flammable gases

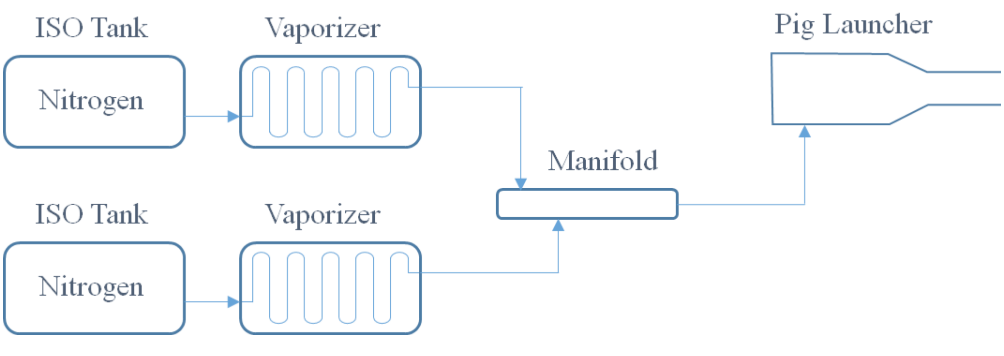


Figure 10: Schematic diagram of Nitrogen injection facilities

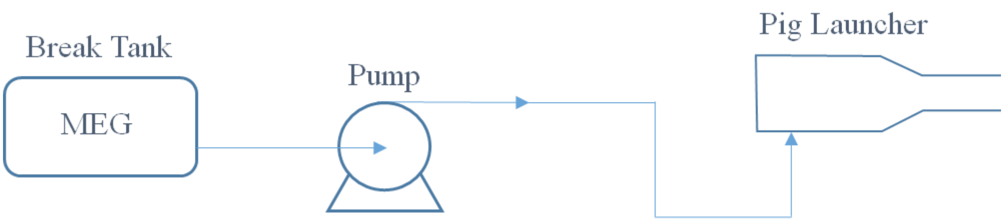


Figure 11: Schematic diagram of MEG injection facilities

Abovementioned requirements are needed since the chemical has to be solved in fresh water. The solution might remain still and stagnant for a specified period. Normal dosage for application of AFFF foams is usually defined from 3% to 6% to be dissolved in water.

As per the mentioned requirements and with consultancy with professional AFFF foam providers, implemented chemical for forming the desired foam was chosen to be Medium Expansion Foam with code of AT150 which has the following properties:

Appearance	Liquid
Color	Clear Liquid
Specific Gravity in20c	1.0±0.02
PH	6.5-8.5
Drainage Time25%	3-6 Min
Sediments %Vol	None
Film Forming	Yes
ST	<20
Shelf Life	2 Years
Packaging	Plastic Drum – 200Lt

Table 3: Typical Properties of Medium Expansion AFFF Foam [12]

This foam is mixed with fresh water with a mixing percentage of 6% by means of a device called inductor; and is expanded through a foam expansion nozzle. The expansion ratio of medium expansion foams are usually stated between 20 to1 and 200 to 1. For this kind of foam, the expansion ratio of almost 20 to 1 is expressed by its producer [12]. The implemented equipment for mixing, producing and developing the AFFF foam for the purpose of being poured into the pipeline are illustrated in figure 12.

According to the aforementioned procedure for mixing and expansion of AFFF foam, the required amount of foam which needs to be considered corresponding to almost 200 meters of 32" pipeline and 300 meters of 18" pipeline (length of the pipeline behind last pig along with riser, launcher, bends and piping through the platform) is calculated as per following equations. It should also be mentioned that since the expanded foam loses its expanded state and turns back into the water/foam mixture within a certain period of time (drainage time), an extra amount of 10% is conservatively needed to be calculated in order to compensate this volume loss and provide a better estimation.

AFFF Foam Calculations for 32" Pipeline:

Pipeline Internal Diameter:	$ID = 771.6\ mm$
Pipeline Cross Section Area	$A = \frac{\pi}{4} \times ID^2 = 0.4676\ m^2$
Volume of Expanded Foam	$V = 1.1 \times 200 \times 0.4676 = 102.87\ m^3$
Volume of Water/Foam Mixture	$V_M = \frac{V}{Expansion\ Ratio} = \frac{102.87}{20} = 5.14\ m^3$
Volume of AFFF Foam	$V_F = 0.06 \times V_M = 0.308\ m^3 = 308\ Lit$

AFFF Foam Calculations for 18" Pipeline:

Pipeline Internal Diameter	$ID = 425.2\ mm$
Pipeline Cross Section Area	$A = \frac{\pi}{4} \times ID^2 = 0.142\ m^2$
Volume of Expanded Foam	$V = 1.1 \times 300 \times 0.142 = 46.86\ m^3$
Volume of Water/Foam Mixture	$V_M = \frac{V}{Expansion\ Ratio} = \frac{46.86}{20} = 2.34\ m^3$
Volume of AFFF Foam:	$V_F = 0.06 \times V_M = 0.140\ m^3 = 140\ Lit$

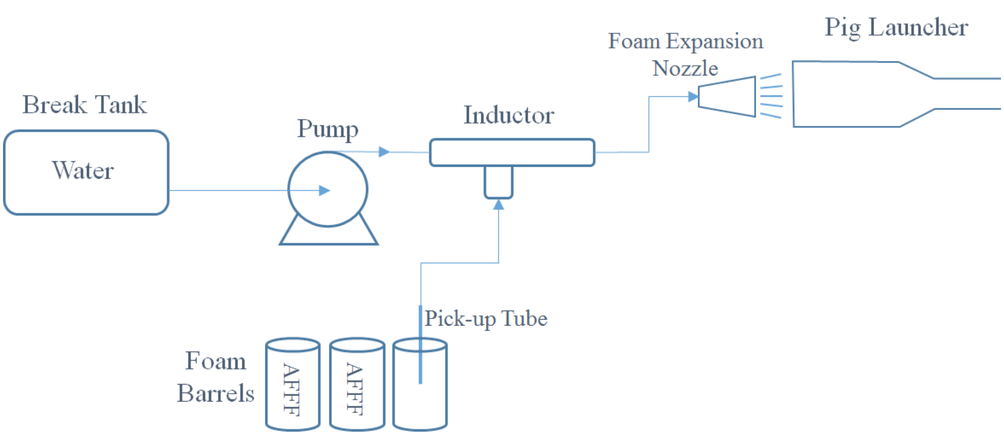


Figure 12: Schematic diagram of AFFF foam mixing, producing and developing equipment

Equipment Preparation

When performing a sensitive high-risk offshore project, it is highly essential that all equipment and accessories be fully checked and prepared. In this matter, there are some major items that need to be taken under consideration.

- All equipment and facilities should be checked and operated at onshore.

- Full process circuit of each operational section of project should once be run at onshore.
- Each equipment should have a spare unit with the same characteristics.
- All the equipment`s parts and accessories should be followed by enough spare parts.
- Consuming materials should be ordered with extra amounts for backup and unpredicted cases.

Figures 13-15 present the implemented equipment in this project.

OPERATIONAL ACTIVITIES

The project was commenced in May 2017 on an offshore platform in South Pars Gas Field. The whole operational activities on both pipelines were completed within less than 4 days. For performing the job, all equipment was placed on a supply vessel landing beside the platform. Hose connections were made from vessel to the platform for injection of Nitrogen, MEG and water for making foam.

Safety Requirements

In order to provide a fully safe condition for performing hot work operation on the pipelines at the platform, there are some safety considerations and criteria which need to be taken into account.

Before performing work involving an atmosphere that may contain an explosive gas, the atmosphere may need to be tested to determine if a flammable mixture is present. Where atmospheric testing is required, it must be done before work begins and may be required at regular intervals while work continues. The most common unit of measurement is the percentage of the lower explosive limit (% LEL). The LEL is the minimum amount of fuel that must be present in air to ignite. If the air/fuel mixture is below the LEL, it is considered too “lean” and will not ignite [13]. Table 4 shows the LEL limits for some hydrocarbon gases.

Methane	Ethane	Propane	Butane
5%	3%	2.3%	1.9%

Table 4: LEL limits for some hydrocarbon gases [13]

Figure 13: Nitrogen tanks and vaporizers placed on supply vessel [14]

Figure 14: Diesel engine pump [14]

Isolation of 32” Pipeline and Cutting the T-Piece

At the beginning of operational activities on each pipeline, due to previous presence of sour gas in the pipeline and launcher, pressurizing was performed on each launcher by means of Nitrogen injection with MOV valve at closed position, and venting the mixture of Nitrogen and gas for 3 times; Each time with 5 bar pressure.

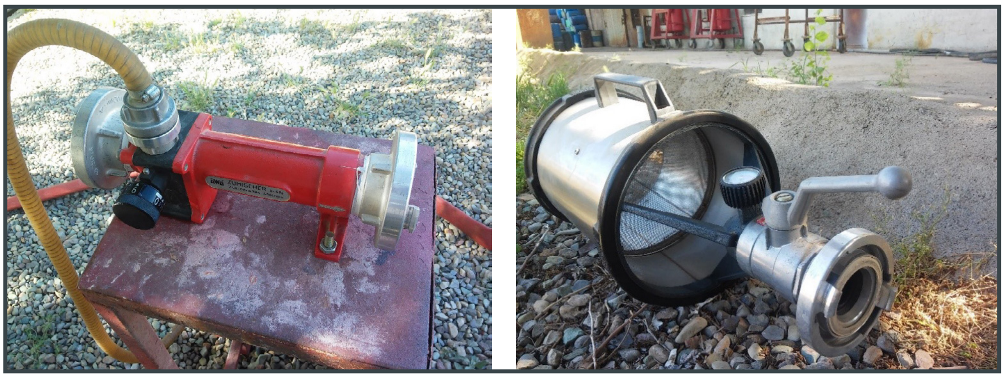


Figure 15: Left: Inductor; Right: Foam Expansion Nozzle [14]

After completion of initial isolation of the launcher, launcher door was opened and LEL and H2S content were measured by HSE officers while using full PPE and BA . Once the hazardous gases in the area were acceptable for presence of other personnel, the rest of designed isolation plan were followed. At each stage of the operation, work permit was issued after checking the LEL and H2S content.

The isolation plan was precisely followed as per the designed approach. Implementation of isolation procedure took almost 10 hours and the system was ready for dismantling the bypass piping and cutting the barred tee which totally took 6 hours during which a low flow rate of Nitrogen was also provided to prepare a safe condition during the hot work process. A summary of applied process and its conditions can be observed in figures 16 and 17.

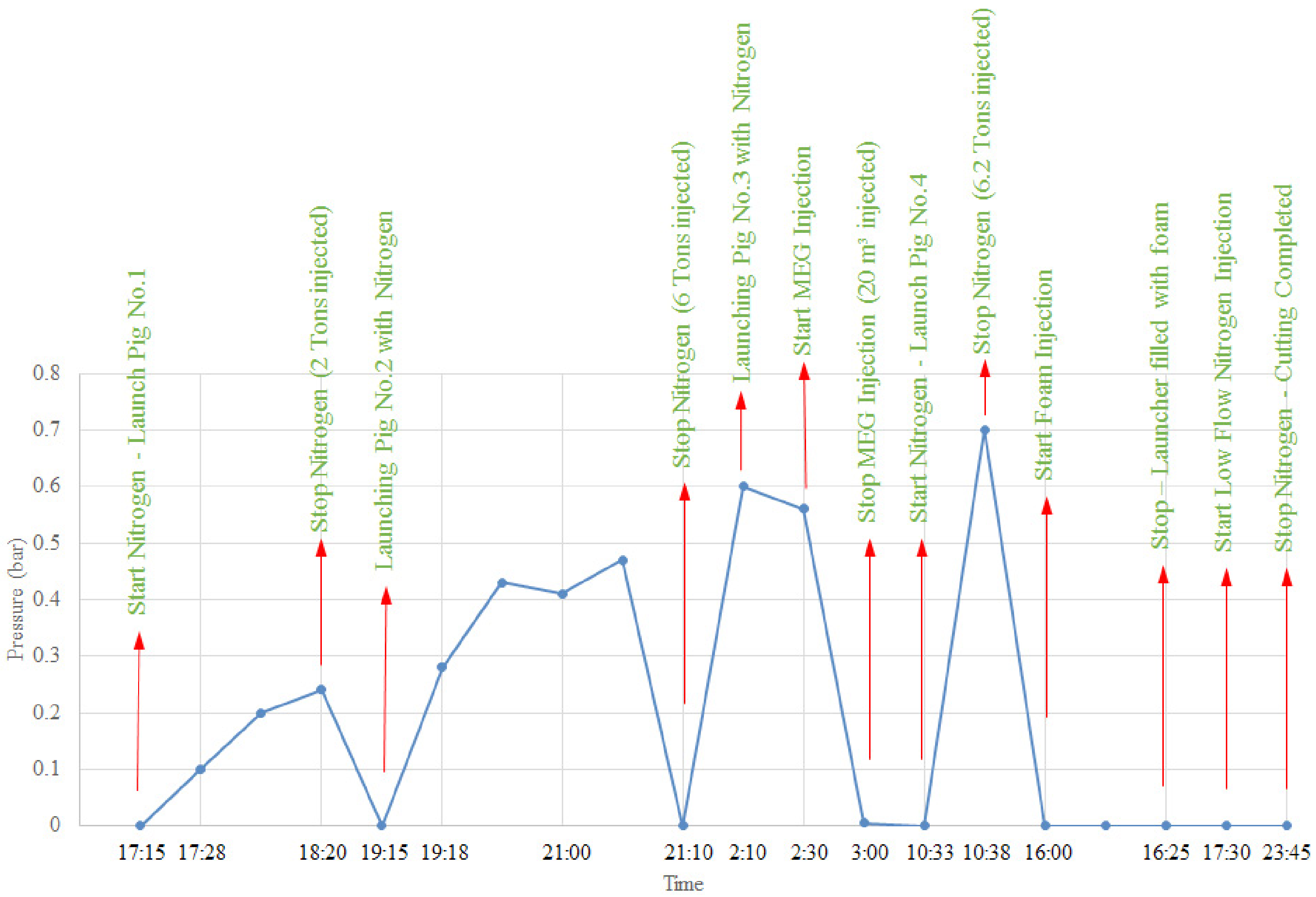


Figure 16: Summary of isolation operation on 32" pipeline [14]

Figure 17: Left: Foam injection into 32" launcher; Middle: 32" launcher filled with foam; Right: Receiving foam at drain in bypass pipe [14]

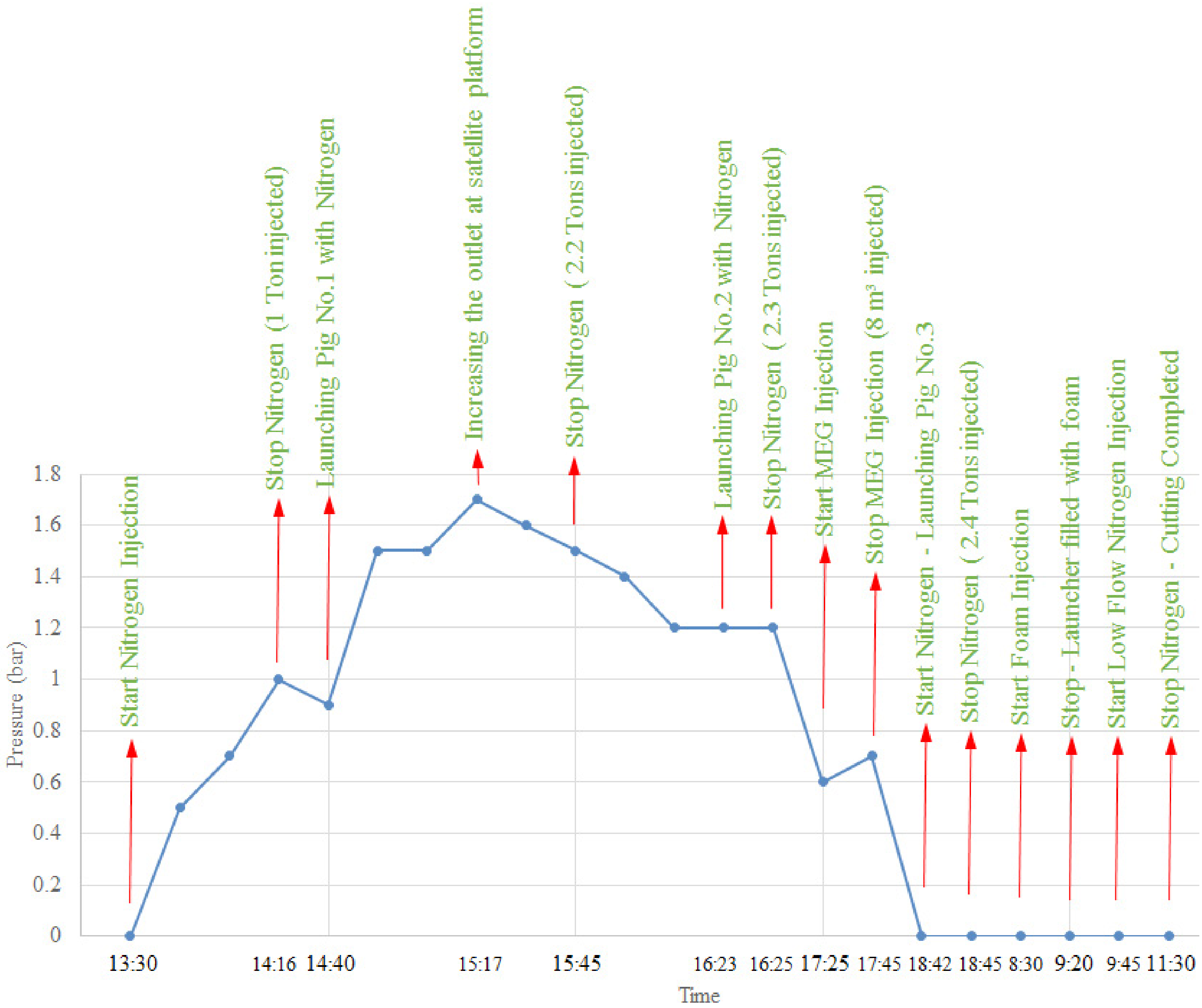


Figure 18: Summary of isolation operation on 18" pipeline [14]

Figure 19: Left: Receiving foram at 18" bypass pipe, Right: Cutting the 18" barred tee piece [14]

"This isolation method, in addition to being remarkably cost effective, utilizes the simplest possible facilities with the most user-friendly approach leading to an easy-to-use, fast and affordable technique resulting in a high operational safety condition.

Pooya Gholami

Isolation of 18" Pipeline and Cutting the T-Piece

The same series of activities were performed for 18" pipeline. The total isolation operation on this pipeline took 6 hours and was followed by 3 hours of low flow Nitrogen injection during cutting the barred tee to prepare a complete safe condition during the hot work operation. A summary of applied process and it conditions for the 18" pipeline can be observed in figures 18 and 19.

CONCLUSION

There have been several methods and technologies for pipeline isolation in oil and gas industry each of which come with their own advantages and disadvantages. There are miscellaneous parameters such as time, cost, pipeline location, accessibility of the ideal technology, operational safety of the method etc. affecting the decision for choosing the desired isolation method. The implemented method for pipeline isolation in this study, in addition to being remarkably cost effective, utilizes the simplest possible facilities with the most user-friendly approach leading to an easy-to-use, fast and affordable technique resulting in a high operational safety condition in live offshore platforms.

During the operational activities of this project, and each time the launcher door was opened, LEL and H2S content were measured in the environment before performing any activity which involved manpower presence. As all the steps of this isolation designed approach were followed precisely, the measured LEL and H2S content were always zero at all the stages.

After completion of isolation operation and approval of safe conditions, the barred tee pieces were cut and the bypass line was removed successfully without and problematic issue. The implemented procedure showed a reliable result in performing safe isolation for hot work operations. The remaining pigs and material inside the pipeline were recovered during restarting the refinery after shut down.

Acknowledgment

The authors would like to thank IPEC for permission to publish this paper. The authors also express their sincere appreciation to Client for cooperation and full support during operation of this project in South Pars Gad Field.

References

[1] Henning Bø, T.D. Williamson, Inc., "Platform Decommissioning: Case Studies in Pipeline Network Reconfiguration", Pigging Products & Services Association (PPSA) Seminar, 2015
[2] Chevron Pipe Line Company, Isolation of Hazardous Energy Standard, January 2013
[3] Mark Smith, Elaine Maruca, "Getting it Right the First Time: 100% Isolation", PLIDCO, World Pipelines, May 2014
[4] Jostein Aleksandersen, Edd Tveit, Plugging Specialists International, "The Smart Plug: A Remotely Controlled Pipeline Isolation System", the Eleventh International Offshore and Polar Engineering Conference, Stavanger, Norway, 17-22 June 2001
[5] AK ARORA, AD (AI), "Case Study: Flash Fire during Underground Pipeline Repair", Oil Industry Safety Directorate, Process and Engineering Group
[6] Stats Group, Products and Services, Isolation and Intervention
[7] Norsk olje & gass, "Best practice for isolation when working on hydrocarbon equipment: planning, isolation and reinstatement", Report by Norwegian Oil and Gas, 21 June 2013
[8] James E. A. John, Theo G. Keith, "Gas Dynamics", Third Edition, Published by Pearson Prentice Hall, 2006
[9] DOW Chemical Company, Engineering and Operating Guide
[10] Schlumberger, PUREMEG, Monoethylene Glycol Reclamation and Regeneration Unit
[11] MEGlobal, Ethylene Glycol Product Guide
[12] ATASHBAS PARS, Medium Expansion Foam (AT150) Data Sheet
[13] Occupational Health and Safety Code, "Fire and Explosion Hazards", Explanation Guide, Part 10, 2009
[14] IPEC Confidential Documents of Projects` Histories, 2014-2018

Authors

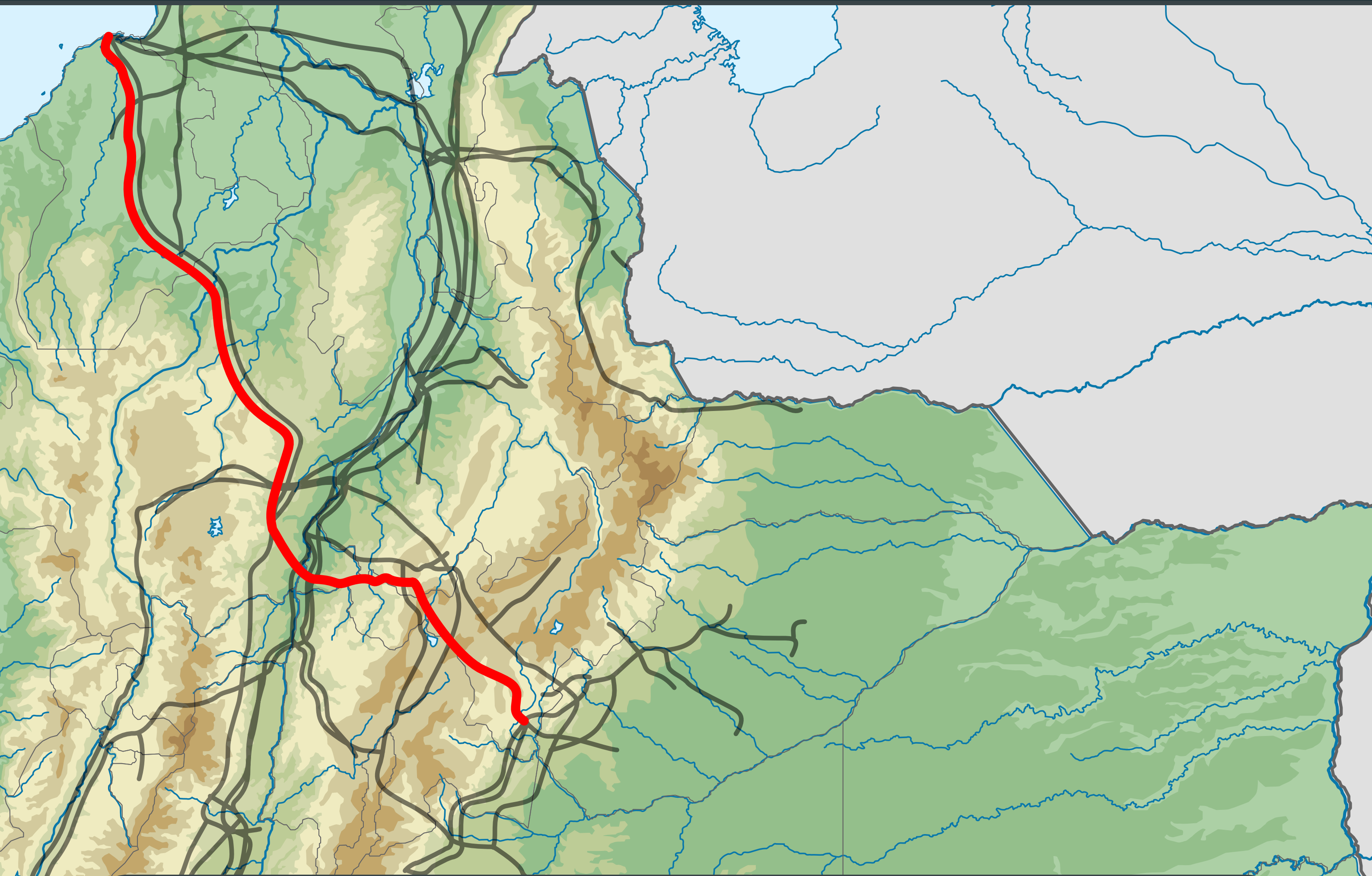
Pooya Gholami
IPEC, Pipeline and Process Services
Operation Manager
pooyagholami@gmail.com

Hadi Tabassomi
IPEC, Pipeline and Process Services
Chairman of the Board and Engineering Director
tabassomi@ipecgroup.net

Mahdi Nouri
IPEC, Pipeline and Process Services
Member of the Board and Pipeline Projects Director
nouri@ipecgroup.net

APPLICABILITY OF DYNAMIC BEHAVIOUR STUDIES ON OCENSA'S OFFSHORE PIPELINE OVER LIQUEFIED SEABED

Alejandro Marín > Oleoducto Central S.A (OCENSA)



ABSTRACT

Applicability of a simplified pipe-soil interaction model on determining pipeline's dynamic behaviour, once seabed support is lost due to seabed liquefaction, is evaluated over Oleoducto Central-Ocensa (central oil pipeline). Located in Colombia, South-America, this transportation line has 12.5km of subsea pipeline in the Gulf of Morrosquillo-Caribbean Sea. Crude oil from eastern plains of Colombia, is transported throughout this 42" pipeline, which is stored at the maritime terminal of Coveñas, before being loaded to tankers for exportation.

Pipeline's loss of support length is function of metocean features such as wave height, length, period, seabed depth, among others. Once the simplified pipe-soil interaction model is applied, calculation of pipeline's dynamic behaviour in terms of wall stress, for typical Gulf of Morrosquillo's metocean environment may be possible; as of this, critical conditions for pipeline's operation are identified, and seabed geotechnical maintenance plans are defined, based on rational methods, in order to minimise harm potential over pipeline's integrity due to seabed loss of support.

INTRODUCTION

Due to oil & gas offshore production, seabed pipeline's deployment is necessary for hydrocarbons transportation, through shallow and water depths greater than 1000 meters. In the same way, transportation lines and additional facilities such as Tanker Loading Units (TLU) must be installed, for transfer, connection and loading activities in order to guarantee crude oil exportation to tankers. Therefore, it is mandatory the undertaking of rigorous and exhaustive analysis of seabed behaviour, in order to develop accurate integrity and maintenance plans based on metocean features (i.e. wave height, length, period, seabed depth, tidal and wave current), and factors as geohazards associated to metocean conditions, like landslides on the continental slopes and stress states' variations within the seabed, leading to liquefaction.

Evidence of large seabed liquefaction areas are reported in Christian et al. (1997), where identification of large zones exceeding 100m of submarine slope failures, due to seabed liquefaction were exposed close to the Fraser River Delta, as well as those reported within the Yellow River Delta by Jia et al. (2014). Therefore, large scale seabed failures due to earthquakes and wave induced stresses causing seabed liquefaction, are a reality, which must be addressed to guarantee subsea pipelines' integrity.

It has been also identified, that influence of wave induced pressure over seabed is greater in shallow water than in deeper water. Above mentioned, increases seabed liquefaction potential as consequence of pore water pressure raising. However, influence of grain-size on seabed liquefaction, among other parameters, must be addressed; aforementioned potential decreases once seabed fine grain-size content increases (i.e. silts and clays), regardless a high wave induced pressure over the latter.

Even though it is necessary to embrace comprehensive methods on describing seabed liquefaction, and even more, interaction between liquefied soil and pipeline dynamic behaviour, there is still deficiencies to allow pipelines operators to stablish criteria for decision making based on its quantification. Nevertheless, experimental studies as those conducted by Teh et al. (2003) have demonstrated that for subsea pipelines design, current design methods and approaches fulfil sufficiently stability requirements for a non-liquefied seabed, but are not adequate once the seabed experiences liquefaction. This, due to absence of liquefied seabed characterisation and a subsequent deficiency on pipe-liquefied soil interaction prediction.

Moreover, Wang et al. (2004) developed a numerical approach based on Biot's consolidation theory where interaction between soil skeleton and inter-granular water is regarded, but neglecting acceleration components for simplification. Similar developments based on Biot´s consolidation theory such as the undertaken by Zienkiewicz (1981), Ulker (2009) and Ulker (2012) have related fully dynamic, partially dynamic and quasi-static formulations to account the seabed response to a wave-induced pressure, as a function of metocean and seabed parameters variation.

Linear wave theory has been applied to associate seabed liquefaction onset, and its transient behaviour, to wave induced pressure over the seabed. Gao et al. (2011) established the seabed response in terms of vertical stress, horizontal stress, shear stress and pore water pressure entirely as function of the harmonic wave-load [(2πx / L) – (2πt / T)] and its repercussion at any depth by means of classic Boussinesq principle.

Although liquefaction potential decreases as fine grain-size content increases, regardless a high wave induced pressure over the seabed, once an almost saturated porous media (i.e. S≈1) is assumed, wave induced stress over soil may develop an instantaneously reduction of the mean effective stress (Ulker, 2012). Consequently, instantaneous liquefaction may occur even though a low soil permeability is given (i.e. dense sands or high fine grain-size content soils).

Additionally, according to Ulker (2009), cyclic wave induced pressure over seabed develop downward (i.e. suction or negative pore water pressure) and upward pore water flow. The latter, leads to wave induced liquefaction once seepage force, governed by upward flow, overtakes the submerged unit weight of soil (Figure 1).

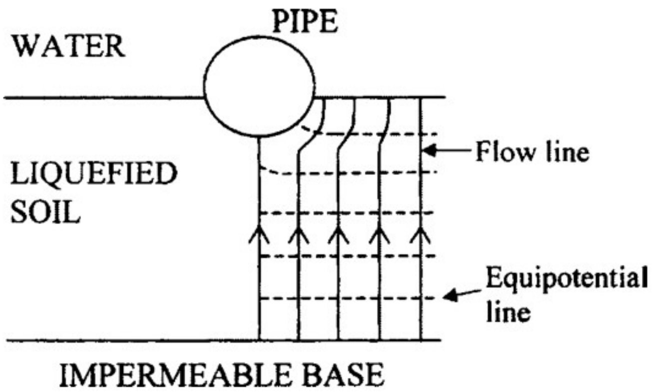


Figure 1: Upward pore water flow during seabed liquefaction, after Teh et al. (2006)

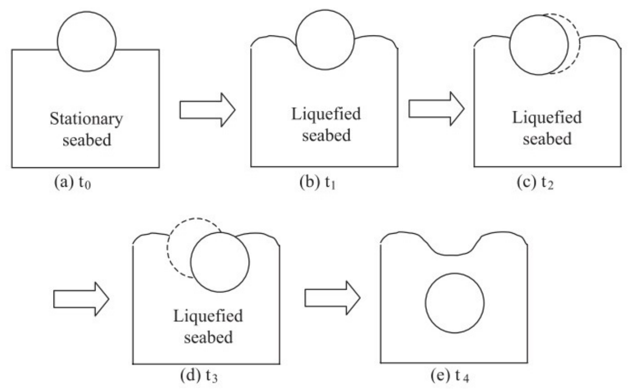


Figure 2: Instability phases throughout time for a heavy pipeline over liquefied seabed, after Teh et al. (2003)

According to experimental studies conducted by Teh et al. (2003), heavy pipelines (i.e. large diameter) instability phases, once seabed liquefaction takes place, can be described as plotted in Figure 2.

Regarding this scenario, for time t_1, the hydrodynamic wave induced pressure is not sufficient to move the heavy pipeline, but is large enough to liquefy the seabed (i.e. the pipeline is stable); for times t_2 and t_3 the pipeline starts to move and therefore sinking into the liquefied soil mass, up to a final position for time t_4.

Furthermore, according to Teh et al. (2006), both positive pore pressure and negative pore pressure may take place under cyclic loading around a submarine structure (e.g. a pipeline). Also, the author claims both sinking velocity and depth are greater for a heavier pipe, whilst a lighter pipe (i.e. small diameter pipelines) tends to float once soil liquefies. In order to describe abovementioned behaviours, Teh et al. (2006) stated three different modes governing the extent of pipeline sinking once seabed experiments liquefaction, related to seabed bearing capacity lost associated to depletion of vertical effective stress (i.e. $\sigma'_v = 0$):

- Mode I: For a slow sinking light pipe, the gradient of the increasing pore pressure acts as buoyancy force stopping the downward advance of it;
- Mode II: Pipe stops sinking, due to the increase or recover of soil bearing capacity, once excess of pore water pressure starts dissipating or when the pressure gradient is not sufficient;
- Mode III: For a fast sinking heavy pipe, it will continue to sink whether the sinking velocity is greater than the excess of pore pressure dissipation rate, or the pressure gradient is not enough to act as a buoyant force. Once it reaches a stable stratum, it may stop sinking.

As of this, once pipelines' behaviour in terms of wall stress and strain is desired to be estimated, regarding its sinking degree within the liquefied seabed, it is necessary to define the magnitude of upward pore water flow, once liquefaction takes place. This process is shown schematically in Figure 3.

METHODOLOGY

Since seabed stress field, related to wave motion, which induces liquefaction varies according to simple harmonic motion, seabed dynamic response will be consequently governed by this motion. Thus, seabed dynamic response in terms of stresses and displacements due to liquefaction, is calculated regarding a coupled soil skeleton-pore water flow model.

For practical purposes, liquefied seabed length is equal to the wave length (L) that induces harmonic pressure over it, according to seabed dynamic response approaches conducted by Wang et al. (2004), Ulker et al. (2009) and Ulker (2009; 2012).

Modelling scenarios conducted by Marín (2015), exhibit pipelines' dynamic behaviour where seabed dynamic response, regarding coupled soil skeleton-pore water flow, was accounted. In the study, different pipe diameters and seabed depths were adopted, analysing 10", 16", 24", 36" pipe diameters, and 25m, 50m, 75m and 100m seabed depths, respectively. Figure 4 shows normalised vertical stress variation within seabed, for a 25m seabed depth and T=5s wave period scenario.

After Marín (2015), light pipelines (i.e. 10" and 16") behaviour was found to be sensitive to seabed dynamic response once liquefaction takes place, according to Mode I stated after Teh et al. (2006). Conversely, heavier pipelines (i.e. 24" and 36") behaviour was found to be governed by their own weight, aligned to Mode III after Teh et al. (2006).

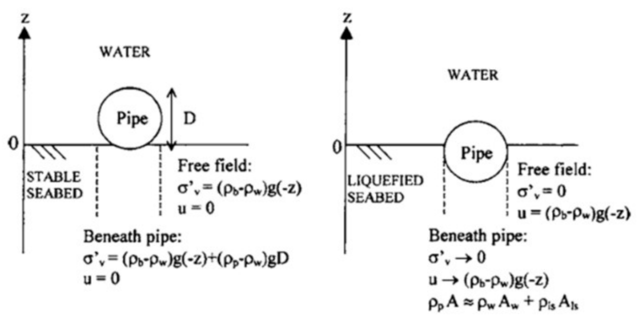


Figure 3: Excess of pore water pressure (u) and vertical effective stress (σ'_v) under a) non-liquefied seabed and b) liquefied seabed, after Teh et al. (2006)

The above mentioned is shown in Figure 5, where the influenced dynamic behaviour for a 10" pipeline, once seabed dynamic response is accounted (in terms of pore water pressure, vertical, horizontal and shear stress variation, plotted as the red curve), is evident if compared to pipeline dynamic behaviour regarding the assumption of an incompressible fluid-like seabed response (i.e. blue curve). On the other hand, in Figure 6 is shown how for a 36" pipe, its dynamic behaviour is not influenced by the liquefied seabed dynamic response, reflected on similar curve paths (i.e. blue and purple curves).

According to previously mentioned, Ocensa's 42" offshore pipeline is not expected to exhibit changes on its dynamic behaviour once seabed dynamic response is accounted. Hence, it may be assumed an incompressible or fluidised-like seabed response, when pipeline dynamic behaviour is desired to be calculated.

However, is relevant to account that models completed by Marín (2015) included low D/t ratios, between 21 and 30, which means significant thickness if compared to its diameter. Above mentioned leads large diameter pipelines' dynamic behaviour to be aligned to Mode III after Teh et al. (2006).

Nevertheless, Ocensa's 42" offshore pipeline D/t ratio is 84, which means reduced thickness compared to its diameter. As of this, it may be suggested a potential for this pipeline, to exhibit a dynamic behaviour influenced by seabed dynamic response, due to a low mass percentage in relation to its size.

Accordingly, models regardless seabed dynamic response (i.e. liquefied soil assumed as an incompressible fluid) and regarding the latter, were conducted. The latter, in order to validate if whether a large diameter pipeline-low D/t ratio, as Ocensa 42", follows Teh et al. (2006) and Marín (2015) suggested dynamic response, or reveals different behaviour based on its high D/t ratio.

ANALYSIS AND RESULTS

Adopted mechanical and operational parameters for modelling are shown in Table 1.

Properties	Value
Steel grade	API 5L X60
Outer diameter	42"
Wall thickness	12.7 mm
Operation pressure	1.0 MPa

Table 1: Pipeline properties adopted for modelling

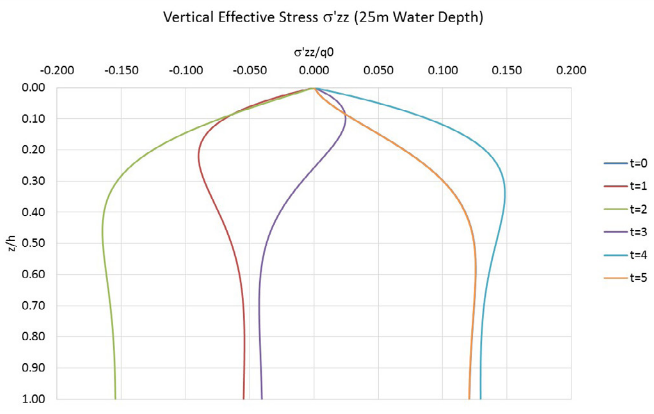


Figure 4: Normalised vertical stress variation within seabed thickness, for T=5s wave period, 25m seabed depth scenario, after Marín (2015)

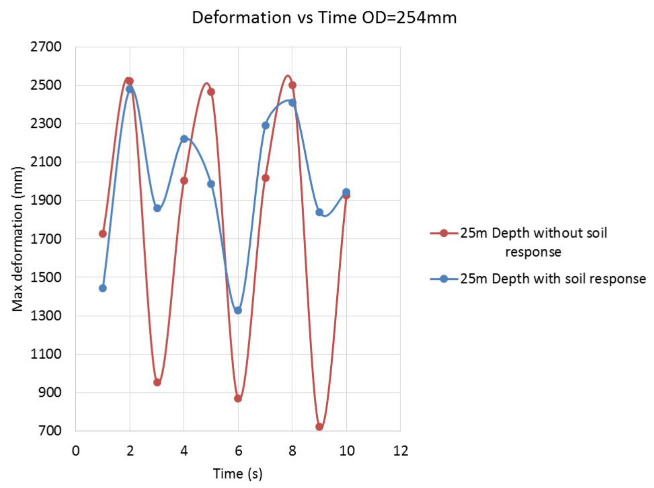


Figure 5: Light pipeline (10") dynamic behaviour variation, as function of seabed dynamic response, after Marín (2015)

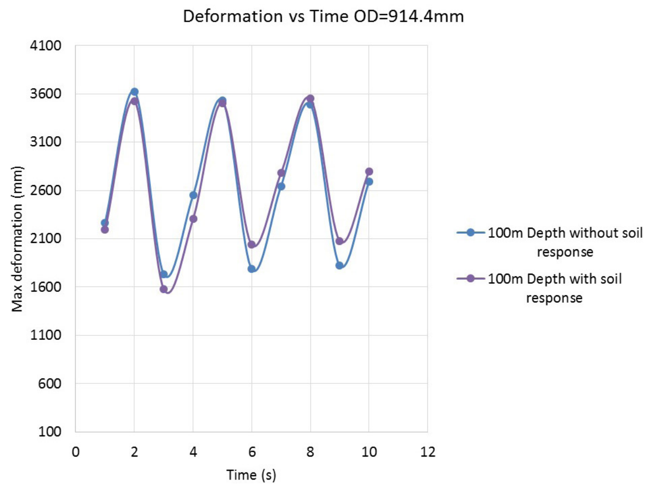


Figure 6: Heavy pipeline (36") dynamic behaviour variation, as function of seabed dynamic response, after Marín (2015)

Accounting relative steady slope throughout Ocensa 42" alignment of 12.5km, mean water depth of 29m for seabed dynamic response and pipeline dynamic behaviour calculations, induced by harmonic wave pressure, was adopted.

For pipeline dynamic behaviour estimation, where seabed dynamic response using coupled model, is not accounted, assumptions done by Foda and Hunt (1993) were embraced. Hence, once seabed is liquefied, its bearing capacity and shear strength reduce to zero. What is more, seabed behaviour may be described as an incompressible liquid, adopting a similar harmonic motion described by wave over it. In terms of metocean environment and based on linear wave theory, abovementioned harmonic motion transmitted to seabed, as a pressure or stresses' field q (p in equation below), is described by means of:

$$p\left(x,t\right)=\frac{p_w g H}{2\cosh\left(kd\right)}e^{i(kw-\omega t)}$$

Where k corresponds to wave number, ω to angular frequency and x to wave length, varying through time t, equal to assumed wave period T.

Complementary, values representing hydrodynamic variables corresponds to real storm for Gulf of Morrosquillo's returning period of 100 years, as follows:

Parameter	Value
Wave height	4.94m
Wave length	100m
Wave period	11 s
Angular frequency	0.571 s^{-1}
Wave number	0.034 m^{-1}

Table 2: Hydrodynamic parameters for returning period of 100 years

For seabed dynamic response estimation, under wave induced cyclic loads in terms of soil skeleton stresses and displacements, once liquefaction takes place, originally methodology proposed by Biot (1962) and further developed by Zienkiewicz (1981) and Ulker et al. (2009), was utilised. This methodology states a coupled model with equations relating soil particles' strain and displacement, to pore water flow induced by wave cyclic load. Aforementioned equations are solved to obtain seabed dynamic response, in terms of vertical stresses, horizontal stresses, shear stresses and pore water pressure, applied as contact pressures in soil-pipeline interaction Finite Element Model (FEM). For seabed dynamic response calculation, a linear system with simultaneous equations set are derived, where non-dimensional matrix is required to be solved, leading to equations shown as follows, whose solving procedures can be consulted in aforementioned references.

$$\begin{bmatrix} \beta\Pi_2-m^2\kappa & im\kappa\frac{\partial}{\partial\bar{z}} & \left(\frac{\beta\Pi_2}{n}+\frac{i}{\Pi_{1x}}-m^2\kappa\right) & im\kappa\frac{\partial}{\partial\bar{z}} \\ im\kappa\frac{\partial}{\partial\bar{z}} & \left(\beta\Pi_2+\kappa\frac{\partial^2}{\partial\bar{z}^2}\right) & im\kappa\frac{\partial}{\partial\bar{z}} & \left(\frac{\beta\Pi_2}{n}+\frac{i}{\Pi_{1z}}+\kappa\frac{\partial^2}{\partial\bar{z}^2}\right) \\ \left(\Pi_2-m^2+\kappa_2\frac{\partial^2}{\partial\bar{z}^2}\right) & im\left(\kappa+\kappa_1+\kappa_2\right)\frac{\partial}{\partial\bar{z}} & \left(\beta\Pi_2-m^2\kappa\right) & im\kappa\frac{\partial}{\partial\bar{z}} \\ im\left(\kappa+\kappa_1+\kappa_2\right)\frac{\partial}{\partial\bar{z}} & \left(\Pi_2-m^2\kappa_2+\frac{\partial^2}{\partial\bar{z}^2}\right) & im\kappa\frac{\partial}{\partial\bar{z}} & \left(\beta\Pi_2+\kappa\frac{\partial^2}{\partial\bar{z}^2}\right) \end{bmatrix} \begin{Bmatrix} U_x \\ U_z \\ \bar{W}_x \\ \bar{W}_z \end{Bmatrix} = 0$$

$$\sigma'_{zz}=\left[\sum_{j=1}^{6}\left(ik\lambda+b_jK\frac{\eta_j}{h}\right)+a_je^{\eta_j\frac{z}{h}}\right]e^{i(kx-\omega t)}$$

$$\sigma'_{xx}=\left[\sum_{j=1}^{6}\left(ikK+b_j\lambda\frac{\eta_j}{h}\right)+a_je^{\eta_j\frac{z}{h}}\right]e^{i(kx-\omega t)}$$

$$\tau'_{xz}=\left[\sum_{j=1}^{6}\left(ikb_j+\frac{\eta_j}{h}\right)+a_je^{\eta_j\frac{z}{h}}\right]e^{i(kx-\omega t)}$$

$$p=-\frac{K_f}{n}\left\{\sum_{j=1}^{6}\left[ik\left(1+c_j\right)+\frac{\eta_j}{h}*\left(b_j+d_j\right)\right]a_je^{\eta_j\frac{z}{h}}\right\}e^{i(kx-\omega t)}$$

According to stated conditions, modelling scenarios were undertaken as:

- Pipeline dynamic behaviour assuming liquefied soil as an incompressible fluid, with equal harmonic motion as overlaying wave;
- Pipeline dynamic behaviour accounting seabed dynamic response, in terms of stresses and pore pressure, by means of soil skeleton-pore water flow coupled model.

As previously mentioned, pipeline liquefied soil (or span) length corresponds to calculated wave length for returning period of 100 years, which exerts cyclic pressure over seabed, along 100 meters. Also, dynamic soil-pipeline interaction models were calculated for times (t) varying between 0 and 11 seconds, which corresponds to adopted wave period for same returning period of 100 years.

Typical graphic output of liquefied seabed-pipeline by means of Finite Element Model, undertaken for Ocensa 42", for maximum deformation is shown in figure 7. For the analysis, symmetry principles in Z axis (i.e. parallel to pipeline alignment) and in X axis (i.e. pipeline and seabed

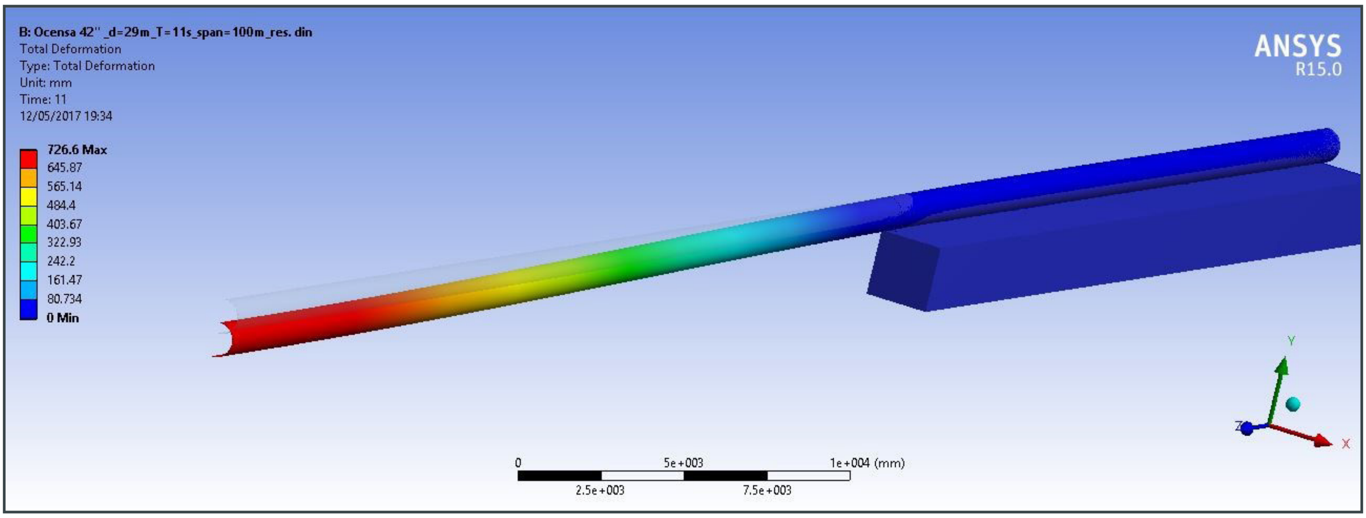


Figure 7: Graphic output from liquefied soil-pipeline Finite Element Model, for Ocensa 42", for maximum deformation

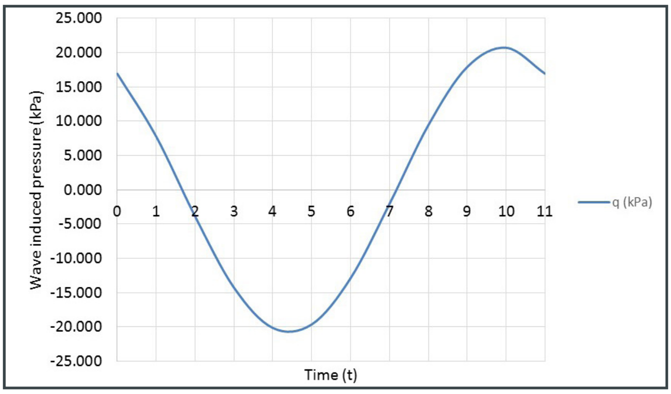


Figure 8: Harmonic wave induced pressure over seabed, for pipeline dynamic behaviour calculation assuming liquefied soil as an incompressible fluid

cross section), in order to minimise number of elements for model solids and its dimensions. The abovementioned allows the model to be analysed in less time and reduces errors related to model solution convergence.

After modelling, plots regarding pipeline's dynamic behaviour in terms of wall stresses and pipe´s deformation, associated to loss of support due to seabed liquefaction were obtained.

Figure 8 shows harmonic wave induced pressure over seabed, for modelling assuming liquefied soil as an incompressible fluid, with equal harmonic motion as overlaying wave, whilst Figure 9 shows point of maximum stress location once seabed support is lost, corresponding to pipeline´s bottom.

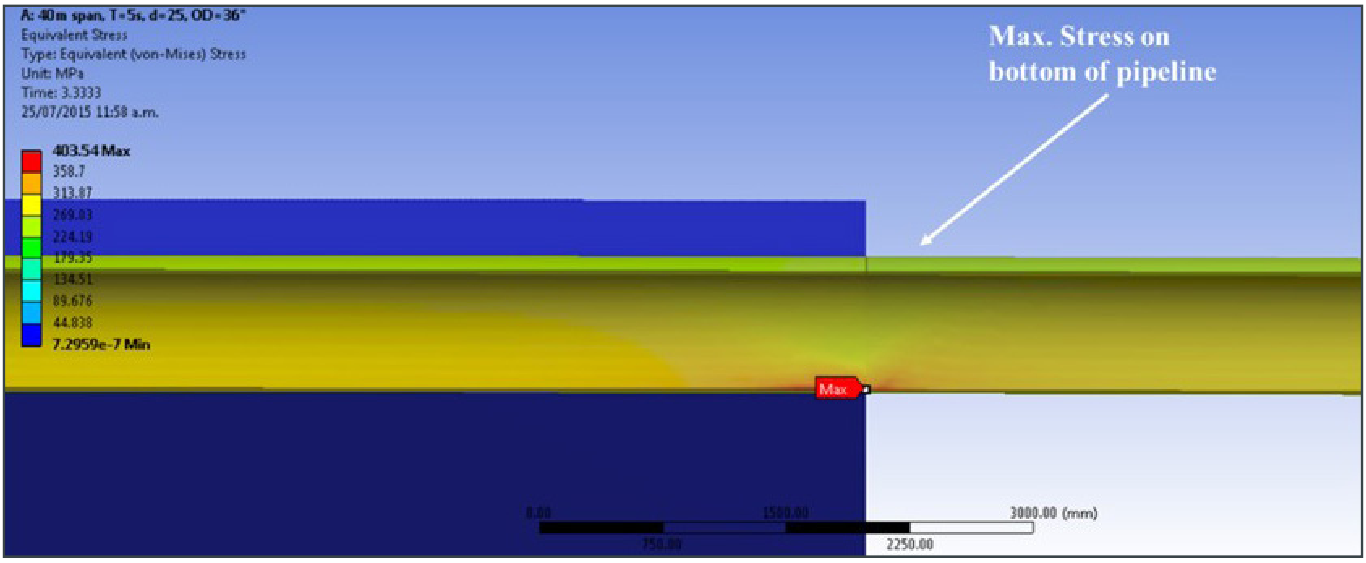


Figure 9: Maximum stress location once seabed support is lost

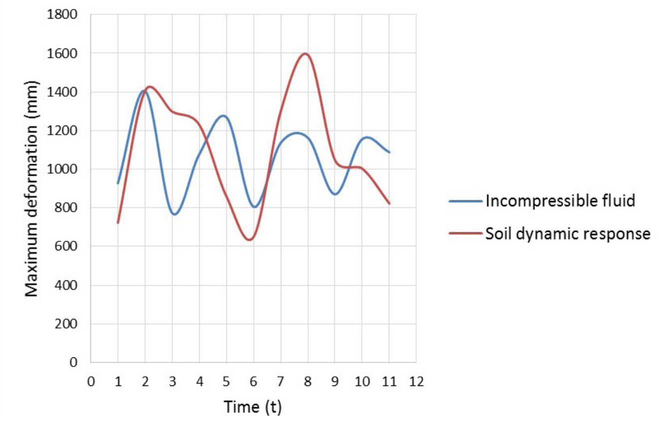


Figure 10: Difference between pipeline´s dynamic behaviour assuming seabed as an incompressible fluid (blue curve) and after calculating seabed dynamic response (red curve)

Finally, Figure 10 plots dynamic behaviour variation once liquefied soil is assumed as an incompressible fluid, and once seabed dynamic response is calculated by means of skeleton-pore water flow coupled model.

CONCLUSIONS

After modelling, differences between pipeline's dynamic behaviour assuming liquefied seabed as an incompressible fluid, and after calculating seabed response as contact pressures over the pipe, were recognised.

Found results differs from conducted by Teh et al. (2006) and Marín (2015), where large diameter pipelines (i.e. heavy pipelines) show trends on their dynamic behaviour once seabed support is lost, governed by their own weight, inertial moment, angular frequency and oscillation amplitude, regardless dynamic seabed response.

Behaviour abovementioned is potentially influenced by D/t ratio, due to as previously stated, in spite of being a large diameter pipeline, associated mass is low regarding its reduced thickness value. The latter, since external hydrostatic pressure requirements for Ocensa´s 42" offshore pipeline are low related to its shallow water location.

Therefore, a potential of being influenced by liquefied seabed response under influence of wave cyclic loads, for the studied pipeline may be suggested. In this way, it is recommended to complete soil-pipeline interaction models once integrity and maintenance plans are undertaken.

Finally, it is also recommendable to complement soil-pipeline interaction models with Vortex Induced Vibration (VIV) analysis, addressing to identify potential pipeline damage associated to fatigue induced by cyclic stresses.

To do so, periodic submarine inspections and regular bathymetry studies must be conducted, in order to determine and identify critical span lengths; additionally, constant metocean parameters variations and weather forecast monitoring must be rigorously done, since accuracy on obtaining these variables is vital to models' representativeness.

References

- Christian, H., Woeller, D., Robertson, P.K. and Courtney, R.C. (1997) 'Site investigations to evaluate flow liquefaction slides at Sand Heads, Fraser River delta', Canadian Geotechnical Journal, 34(3), pp. 384-397.
- Foda, M. and Hunt, J. (1993) 'A nonlinear model for the fluidization of marine mud by waves', Journal of Geophysical Research, 98(C4), pp. 7039-7047.
- Jia, Y., Zhang, L., Zheng, J., Liu, X., Jeng, D.-S. and Shan, H. (2014) 'Effects of wave-induced seabed liquefaction on sediment re-suspension in the Yellow River Delta', Ocean Engineering, 89, pp. 146-156.
- Marín, A. (2015) "Dynamic behaviour of shallow water pipelines due to seabed liquefaction", Thesis for MSc in Pipeline Engineering Degree, Newcastle University.
- Ulker, M. (2009) 'Dynamics of saturated porous media: Wave induced response and instability of seabed' Rahman, M. and Guddati, M. ProQuest, UMI Dissertations Publishing.
- Ulker, M.B.C. (2012) 'Pore Pressure, Stress Distributions, and Instantaneous Liquefaction of Two-Layer Soil under Waves', J. Water. Port Coast. Ocean Eng.-ASCE, 138(6), pp. 435-450.
- Ulker, M.B.C. and Rahman, M.S. (2009) 'Response of saturated and nearly saturated porous media: Different formulations and their applicability', International Journal for Numerical and Analytical Methods in Geomechanics, 33(5), pp. 633-664.
- Ulker, M.B.C., Rahman, M.S. and Jeng, D.S. (2009) 'Wave-induced response of seabed: Various formulations and their applicability', Applied Ocean Research, 31(1), pp. 12-24.
- Teh, T., Palmer, A., Bolton, M.D. and Damgaard, J. (2006) 'Stability of Submarine Pipelines on Liquefied Seabeds', Journal of Waterway, Port, Coastal and Ocean Engineering, 132(4), pp. 244-251.
- Teh, T.C., Palmer, A. and Damgaard, J. (2003) 'Experimental study of marine pipelines on unstable and liquefied seabed', Coast. Eng., 50(1), pp. 1-17.
- Wang, J., Zhang, B. and Nogami, T. (2004) 'Wave-induced seabed response analysis by radial point interpolation meshless method', Ocean Eng., 31(1), pp. 21-42.
- Zienkiewicz, O., Chang CT, Bettess P. 18 (1981) 'Drained, undrained, consolidating and dynamic behaviour assumptions in soils: Zienkiewicz, O C; Chang, C T; Bettess, P Geotechnique, V30, N4, Dec 1980, P385–395' Chang CT, B.P., pp. 48-4

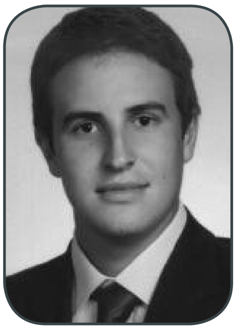
Author

Alejandro Marín

Oleoducto Central S.A (OCENSA)

Senior Integrity Engineer

Alejandro.marin@ocensa.com.co



14TH PIPELINE TECHNOLOGY CONFERENCE

Europe's Leading Pipeline Conference and Exhibition

19-21 MARCH 2019, ESTREL CONVENTION CENTER, BERLIN, GERMANY

EVENT PREVIEW

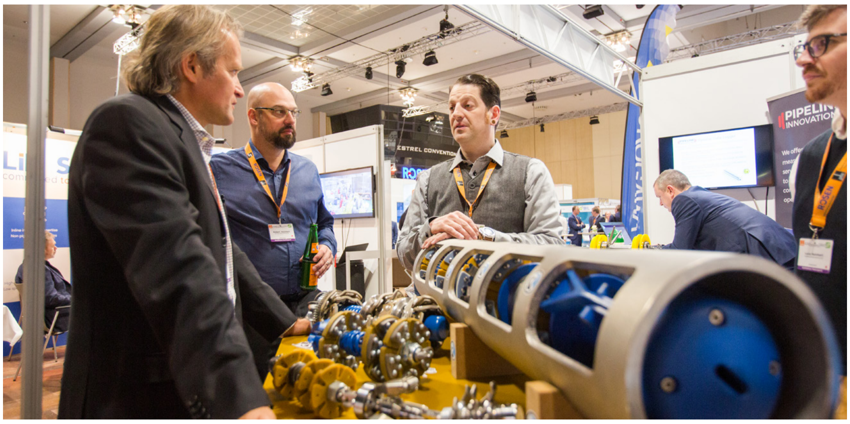
700+ DELEGATES | 80+ EXHIBITORS | 50+ DIFFERENT NATIONS

From 18-21 March 2019 Europe's leading conference and exhibition on pipeline systems, the Pipeline Technology Conference, will take place for the 14th time. The core ptc (19-21) will be supplemented with two side conferences and a number of seminars, taking place on 18th of march.

ptc 2019 offers again opportunities for operators as well as technology and service providers to exchange latest onshore and offshore technologies and new developments supporting the energy strategies world-wide. More than 700 delegates and 80 exhibitors are expected to participate in the 14th ptc in Berlin.

The practical nature of ptc was always based on the cooperation with our technical and scientific supporters and on a top-class international advisory committee. The conference will feature lectures and presentations on all aspects surrounding oil, gas, water and product high, medium and low pressure pipeline systems.

Please take a closer look into he "First Announcement and Call for Papers" and get involved now - send in your presentation suggestion and reserve your booth at the exhibition.



70+ Pipeline Operators

16 thematic focuses at ptc 2019

Construction
Corrosion Protection
Cyber Security
Fiber Optic Sensing
Inline Inspection
Integrity Management
Leak Detection
Maintenance & Repair
Materials
Offshore Technologies
Operational Improvements
Planning & Design
Pump & Compressor Stations
Qualification & Recruitment
Trenchless Technologies
Valves & Fittings

2 ptc Side Conferences on

Qualification & Recruitment
Public Perception

5 ptc Seminars

- Pipeline Life-Cycle Extension Strategies
- Inline Inspection
- Offshore
- Geohazards in Pipeline Engineering
- Corrosion Protection
- Pipeline Leak Detection

ptc

14TH PIPELINE TECHNOLOGY CONFERENCE & EXHIBITION

EUROPE'S LEADING PIPELINE EVENT

THE ANNUAL GATHERING OF THE INTERNATIONAL PIPELINE COMMUNITY IN THE HEART OF EUROPE

After starting as a small side event of the huge HANNOVER MESSE trade show in 2006, the Pipeline Technology Conference developed into Europe's largest pipeline conference and exhibition. Since 2012 the EITEP Institute organizes the ptc on its own and moved the event to Berlin in 2014.

EXHIBITORS OF PTC 2018:

3P SERVICES, ENTEGRA, metegrity, ROM STAR GROUP, a.hak INDUSTRIAL SERVICES, GLD GOTTSBERG LEAK DETECTION, MONTI, ROSEN, CREAFORM AMETEK, GSTT, MSA The Safety Company, sebaKMT, Applus RTD, HERRENKNECHT Tunnelling Systems, NDT GLOBAL, SHAWCOR, Asel-Tech, HIMA SMART SAFETY, OptaSense, SIEMENS, ATMOS INTERNATIONAL, IBG HydroTech, PERGAM-SUISSE AG, SOLARES, auma, ILF CONSULTING ENGINEERS, Petro IT, TDW, BIL Die Leitungsauskunft, IMS Robotics, PHOENIX CONTACT, TDC, BUREAU VERITAS, PIPELINE INNOVATIONS, TIBCHEMICALS, CITADEL TECHNOLOGIES, DF, PTI PIPELINE TRANSPORT INSTITUTE, TNO innovation for life, CLOCK SPRING, Schöngen, PIPESURVEY, TÜV SÜD, DENSO, kebu, Polyguard, VACUWORX, DENSO, KÖTTER, PIGGING PRODUCTS & SERVICES ASSOCIATION, VENTEC, DIRECT-C, KROHNE, premier COATINGS LTD, WORLD PIPELINES, Vulkan Verlag, KTN, PSI, WORLDWIDE GROUP, DNV·GL, LIN SCAN, PRIMUS LINE, YOKOGAWA, DVGW, MAATS, RAM 100, YPP, EMPIT, STREICHER, Reinhart Hydrocleaning SA, ZWICK

Platinum Sponsors

Golden Sponsors

Silver Sponsors

Become a sponsor of the Pipeline Technology Conference and we will include your company in all our ptc marketing activities from the date of registration

Pre-conference Marketing

- Adverts in Media Partner Journals
- ptc Website
- Pipeline Technology Journal (ptj)
- ptc + ptj Newsletter
- Press Releases
- Social Media Activities
- Brochures
- Letterhead
- Online Banner
- Direct Mailings

Marketing at the Conference

- Conference Bag
- Brochure in Conference Bag
- Banners in the Exhibition Hall
- Banners in Conferences Rooms
- Booth in Preferred Location
- Lanyard
- Event Smartphone App
- Get Together Sponsorship
- Dinner Sponsorship
- Social Media Activities

Post-Conference Marketing

- Press Releases
- ptc + ptj Newsletter
- Final Report
- Social Media Activities
- ptc Website
- Pipeline Technology Journal (ptj)

EITEP Database of Verified Pipeline Addresses

>50,000 EMAILS

- highly international
- updated on a daily basis
- including all previous delegates, speakers, exhibitors

GET IN TOUCH WITH US IF YOU WOULD LIKE TO GET TO KNOW MORE ABOUT OUR SPONSORING OPPORTUNITIES.

CONFIRMED EXHIBITORS AS OF 05.10.2018

REGISTER YOUR STAND AT
WWW.PIPELINE-CONFERENCE.COM/STAND-BOOKING

- 50+ DIFFERENT NATIONS
- DELEGATIONS FROM 70+ DIFFERENT PIPELINE OPERATORS FROM ALL AROUND THE WORLD
- 700+ DELEGATES
- 80+ EXHIBITORS
- 100+ PRESENTATIONS
- 25 TECHNICAL SESSIONS
- ACCOMPANYING SCIENTIFIC POSTER SHOW

THEMATIC FOCUSES:

CONSTRUCTION
CORROSION PROTECTION
CYBER SECURITY
FIBER OPTIC SENSING
INLINE INSPECTION
INTEGRITY MANAGEMENT
LEAK DETECTION
MAINTENANCE & REPAIR
MATERIALS
OFFSHORE TECHNOLOGIES
OPERATIONAL IMPROVEMENTS
PLANNING & DESIGN
PUMP & COMPRESSOR STATIONS
QUALIFICATION & RECRUITMENT
TRENCHLESS TECHNOLOGIES
VALVES & FITTINGS

ptj JOB & CAREER MARKET

YOUR OPPORTUNITY TO ATTRACT PROFESSIONALS AND HIGH POTENTIALS

The international pipeline community is in need of additional personnel.

We need more experienced professionals, but we also need young graduates to join our ranks. Despite attractive working conditions, many companies encounter problems while they are reaching out to potential recruits. There are many competing industry sectors who are also in need of high potentials. This results in many vacant jobs in the pipeline community, for operators, technology providers and service providers alike.

This necessity has driven us to develop a new service for the global pipeline industry. For this reason, we organize the first ptc side conference on Qualification and Recruitment.

ptc side conference on

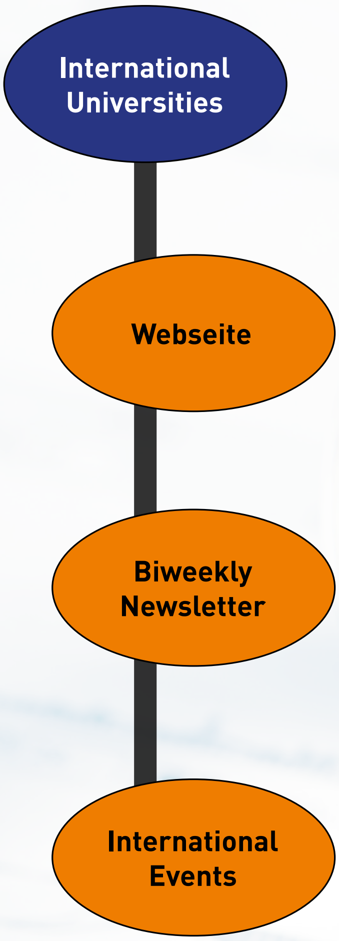
Qualification and Recruitment

18 March 2019

Estrel Convention Center Berlin, Germany

In the frame of ptc

ONE SERVICE - MULTIPLE CHANNELS



Offensive approach: We push forward and generate attention to our career market directly at the universities. We also collect CVs from international graduates and experts and forward it directly to you.

Continuous promotion : Your vacancies are published on the Pipeline Technology Journal (ptj) website. In Addition, the ptj contains your vacancies too.

Dead on target: We send your vacancies or your company profile to our database of 50,000 international pipeline professionals.

Physical appearance: The job & career market has an individual booth during all EITEP events.

Questions?

Please contact Mr. Admir Celovic for further information and booking requests.

celovic@eitep.de
+49 / 511 / 90992-20

You get:

The most cost-effective support to your recruitment efforts available to the market

Automation

Siemens
Germany
www.siemens.com

Yokogawa
Japan
www.yokogawa.com

Certification

Bureau Veritas
Germany
www.bureauveritas.de

Cleaning

Reinhart Hydrocleaning
Switzerland
www.rhc-sa.ch/rhc/

Coating

Denso
Germany
www.denso.de

Kebulin-gesellschaft Kettler
Germany
www.kebu.de

Polyguard Products
United States
www.polyguard.com

Premier Coatings
United Kingdom
www.premiercoatings.com/

RPR Technologies
Norway
www.rprtech.com/

Shawcor
United States
www.shawcor.com

TDC International
Switzerland
www.tdc-int.com

TIB Chemicals
Germany
www.tib-chemicals.com

Construction

BIL
Germany
bil-leitungsauskunft.de

Herrenknecht
Germany
www.herrenknecht.com

IPLOCA - International Pipe Line & Offshore Contractors Association
Switzerland
www.iploca.com

MAX STREICHER
Germany
www.streicher.de/en

Petro IT
Ireland
www.petroit.com

VACUWORX
Netherlands
www.vacuworx.com

Vlentec
The Netherlands
www.vlentec.com

Construction Machinery

Maats
Netherlands
www.maats.com

Worldwide Group
Germany
www.worldwidemachinery.com

Engineering

ILF Consulting Engineers
Germany
www.ilf.com

KÖTTER Consulting Engineers
Germany
www.koetter-consulting.com

Inline Inspection

3P Services
Germany
www.3p-services.com

A.Hak Industrial Services
Netherlands
www.a-hak-is.com

Intero Integrity Services
Netherlands
www.intero-integrity.com/

KTN AS
Norway
www.ktn.no

LIN SCAN
United Arab Emirates
www.linscaninspection.com

NDT Global
Germany
www.ndt-global.com

Pipesurvey International
Netherlands
www.pipesurveyinternational.com

PPSA - Pigging Products and Services Association
United Kingdom
www.ppsa-online.com

Romstar
Malaysia
www.romstargroup.com

Rosen
Switzerland
www.rosen-group.com

Inspection

Ametek – Division Creaform
Germany
www.creaform3d.com

Applus RTD
Germany
www.applusrtd.com

EMPIT
Germany
www.empit.com

Integrity Management

Metegrity
Canada
www.metegrity.com

Pipeline Innovations
United Kingdom
www.pipeline-innovations.com

Leak Detection

Asel-Tech
Brazil
www.asel-tech.com

Atmos International
United Kingdom
www.atmosi.com

Direct-C
Canada
www.direct-c.ca

Entegra
United States
www.entegrasolutions.com

GOTTSBERG Leak Detection
Germany
www.leak-detection.de

MSA
Germany
www.MSAsafety.com/detection

OptaSense
United Kingdom
www.optasense.com

Pergam Suisse
Switzerland
www.pergam-suisse.ch

PSI Software
Germany
www.psioilandgas.com

sebaKMT
Germany
www.sebakmt.com

SolAres (Solgeo / Aresys)
Italy
www.solaresweb.com

COMPANY DIRECTORY

Monitoring

Krohne Messtechnik
Germany
www.krohne.com

Operators

TRAPIL
France
www.trapil.com/en/

Pump and Compressor Stations

TNO
The Netherlands
www.pulsim.tno.nl

Repair

CITADEL TECHNOLOGIES
United States
www.cittech.com

Clock Spring
United States
www.clockspring.com

RAM-100
United States
www.ram100intl.com

T.D. Williamson
United States
www.tdwilliamson.com

Research & Development

Pipeline Transport Institute (PTI LLC)
Russia
www.en.niitn.transneft.ru

Valves & Fittings

AUMA
Germany
www.auma.com

Zwick Armaturen
Germany
www.zwick-armaturen.de

Safety

DEHN & SÖHNE
Germany
www.dehn-international.com/en

HIMA
Germany
www.hima.de

TÜV SÜD Indutrie Service
Germany
www.tuev-sued.de/is

Signage

Franken Plastik
Germany
www.frankenplastik.de/en

Standards & Regulations

DNV GL
Norway
www.dnvgl.com

DVGW - German Technical and Scientific Association for Gas and Water
Germany
www.dvgw.de

Surface Preparation

MONTI - Werkzeuge GmbH
Germany
www.monti.de

Trenchless Technologies

GSTT - German Society for Trenchless Technology
Germany
www.gstt.de

Rädlinger Primus Line
Germany
www.primusline.com

Event Calendar		
gat | wat 2018	23 - 25 October 2018	Berlin, Germany
ADIPEC	12 - 15 November 2018	Abu Dhabi, UAE
14th Pipeline Technology Conference (ptc)	**19 - 21 March 2019**	**Berlin, Germany**
ptc Side Conferences:		
on Qualification & Recruitment	**18 March 2019**	**Berlin, Germany**
on Public Perception	**18 March 2019**	**Berlin, Germany**