

Prediction of Top of Line Corrosion Risk due to Damages in External Pipeline Insulation

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ABSTRACT

This paper presents the methodology adopted to evaluate the effect of external insulation damage on TLC within carbon steel flowlines. A field development, consisting of subsea wells in 830 m water depth, transports wet gas via two 20" diameter production flowlines. The wet gas contains about 1.5 to 2 mol% CO₂. The pipeline system is largely carbon steel with only short lengths made of CRA piping. Lean MEG mixed with corrosion inhibitor is injected at the wellheads for hydrate inhibition. A subsea remotely operated vehicle inspection of the deep water 20" spools revealed insulation damage and bulging. These damages could act as cold spots and lead to enhanced water condensation and TLC on the internal wall of the flowlines. In order to assess the severity of the impact of the damages, a thermal Finite Element Analysis step was undertaken to determine the condensation rates on the inside of the lines. The corresponding TLC rates were then calculated using mechanistic corrosion prediction software considering multiple production conditions. The corrosion assessment helped identify which insulation damages required remedial actions. The TLC rates calculated were later verified by internal pipeline pigging inspection.

Keywords: Insulation, Top of Line Corrosion, Corrosion management, Thermal mapping

INTRODUCTION

A visual inspection of a subsea field development, transporting wet gas, containing approximately 1.5 to 2 mol% of CO₂ to shore, was conducted via ROV (remotely operated vehicle). The pipeline system is largely carbon steel with only short lengths of CRA (corrosion resistant alloy) piping from the wellhead to the production/pigging manifold. Downstream of the pigging manifold the system has 20" carbon steel spools leading to the FTA (flowline termination assembly) and then 20" carbon steel flowlines to the riser platform. Lean MEG (monoethylene glycol) is injected at the wellheads for hydrate inhibition and corrosion inhibitor is mixed with the lean MEG to mitigate

bottom of line corrosion within the pipeline system. The spools and flowline are insulated to control water condensation rates such that the resulting TLC (top of line corrosion) rate can be within the limits of allowed corrosion.

The inspection of the 20" spool piece between the pigging manifold and the FTA revealed that some of the pipeline insulation had been damaged and became partially or fully detached. Bulging was also observed on some locations. The damage resulted from pipeline walking, causing spool deflection and subsequent interaction between the spool insulation and supporting mud mat. These insulation damages could act as cold spots (locations where the internal pipe wall temperature is lower temperature than adjacent areas of pipe where external insulation is intact) and lead to enhanced WCR (water condensation rate) and TLC rates on the internal wall of the flowlines.

OBJECTIVES

The primary objective of this work was to evaluate the effect of external insulation damages on TLC within the flowline spools. The results would provide understanding of the risk and predicted rates of TLC and inform the forward plan for pipeline system integrity management. Specific flow rate cases were selected, representing historic flow conditions along the flowline spools.

This work was performed using the BLC/TLC prediction software MULTICORP/TOPCORP¹ (identified as Corrosion Software in the rest of the paper) developed by the Institute for Corrosion and Multiphase Technology at Ohio University [1-5]. Corrosion Software is mechanistic corrosion prediction software equipped with simplified (i.e. steady state) flow assurance capabilities.

In most cases, WCR inputs were obtained through a thorough thermal analysis performed by Frazer-Nash Consultancy using OLGA¹ (identified as Flow Assurance Software in the rest of the paper). These WCR inputs are used directly to predict TLC rates. The simulation conditions are detailed in the methodology section and the presentation of the results.

SYSTEM DESCRIPTION

Flowline characteristics

The two 20" ID flowlines are about 170 m long and are considered to be horizontal. Their characteristics are shown in Table 1.

Table 1
Pipeline thermal insulation characteristics

20 " Flowline Summary	
U Value (W/m ² /K)	7.4
Pipe Roughness (mm)	0.03
Pipe ID (m)	0.457
Wall Thickness (m)	0.0318
Environment	Sea
Sea temperature (°C)	5
Sea water wind velocity (m/s)	0.1
Thermal Insulation	
Conductivity (W/m/K)	0.167
Thickness (mm)	23

¹ : Trade name

Fluid composition and formation water properties

One CO₂ level was considered: 2 mol%. No H₂S has been detected in these lines.

The undissociated VFA (volatile fatty acid) content is set at 40 ppm, although sensitivity cases without any VFA were also considered.

Fluid flow rates

Table 2 presents the overall operating envelope that was used for the study. More cases, representing historic, current and future production conditions were considered but are not shown in this publication.

Table 2
Flow cases operating envelope

Flowlines & Case No.	Operating conditions	Fluid Composition [wt. %]				Liquid Mass Flow Rate [kg/s]	Liquid Density [kg/m ³]	Gas Mass Flow Rate [kg/s]	Gas Density [kg/m ³]
		Production Fluid (liq)	MEG (liq)	Water (liq)	Gas Mixture				
A-1	Nominal	4.98	1.03	0	93.99	6.93	841.57	108.33	101.21

Insulation damage cases

Several locations of insulation damage were detected on flowline A and B. The following cases were modelled to investigate their effect on WCR and TLC rates.

Case 1 represents intact external insulation.

Case 2 represents pipe with no insulation.

Case 3: 90° insulation damage (Table 3)

- Insulation disbondment between 3 and 6 o'clock.
- Seawater could be present as a film directly around the pipe in a stagnant state as that full adhesion of the remaining insulation cannot be guaranteed.

Table 3
Detailed description of anomaly case 3

	Summary: • Insulation was found to be damaged/dislodged on eastern side, 350mm wide x approx. 250 mm long. End not seen at 6 O'clock position. • Heat diffraction was obvious at upper edges of perforation/tear. • Small section of spool sighted within the dislodged insulation appeared to have paint coating intact. • The damage only evident on the eastern face.
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Case 4: 30° insulation damage (Table 4)

- Insulation disbondment between 5 and 6 o'clock.
- Seawater could be present as a film directly around the pipe in a stagnant state as we full adhesion of the remaining insulation cannot be guaranteed.

Table 4
Detailed description of anomaly case 4

	Summary: • The insulation was found dislodged on the eastern side, approximately 200 mm long and 100mm wide. • Heat diffraction for the damage was noted. • Small section of spool sighted within the dislodged insulation appeared to have paint coating intact. • The insulation damage was only evident on the eastern side.
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THERMAL ANALYSIS

Methodology

To determine the 3D temperature profile within the line, a thermal FEA (finite element analysis) model was set up in Abaqus 2017™, taking into account the line and insulation geometry, thermal properties of the material, operating conditions and internal liquid level. Previous multi-phase CFD (computational fluid dynamics) analysis had shown that within the 20" line flow stratification into separate condensate and gas phases was likely at all operating conditions, with a liquid depth of approximately 5cm for the cases under consideration here, as shown in Figure 1 for typical Flowline A results.

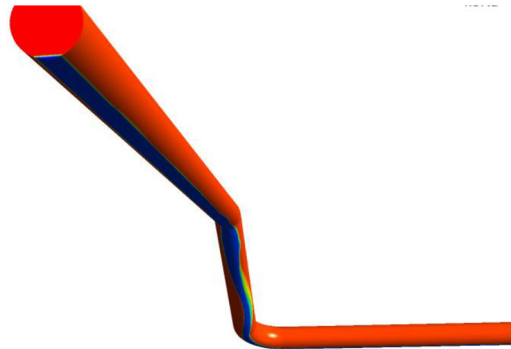


Figure 1: CFD predicted gas volume fraction at exit to the flowline termination assemblies. Blue indicates the presence of a liquid phase. Red indicates the gas phase, where water condensation and TLC can occur. Intermediate colors indicate regions that vary between liquid and gas phases.

Analysis Summary

The analysis method can be summarized as follows:

- A 3D model was created and meshed with quadratic elements, including the steel pipe wall and (where necessary) the external insulation, including any damaged regions.
- Thermal properties were assigned to all components as follows:
 - Source and sink temperatures were set for the internal and external fluids;
 - Thermal conductivity values were provided for the steel and insulation materials.
 - All internal and external surfaces were assigned a heat transfer coefficient, to determine the transfer of heat from the fluid into the surface (internal) or vice versa for external surfaces;

These properties are sufficient to determine the heat fluxes and material temperatures throughout the system

- The thermal FEA solver then iterates to determine the 3D heat fluxes and temperatures for every cell within the model, until a steady state equilibrium condition is reached.

- Once converged, the temperature differential between the gas temperature and the local wall temperature was used to calculate the water condensation rate at each point on the gas-washed inner surface of the line.

Geometries Assessed

Four separate three-dimensional run geometries were considered:

- Case 1: Nominal case with 23mm of complete insulation around the entire circumference;
- Case 2: Uninsulated case, all insulation removed;
- Case 3: Damaged conditions, 90° of insulation loss from the three o'clock to six o'clock positions over a 350mm length of line;
- Case 4: Damaged conditions, 30° of insulation loss from the five o'clock to six o'clock positions over a 300mm length of line.

In all cases, the computational domain was large enough to encompass the entire region thermally affected by the insulation damage, ensuring the model was independent of the pipe end conditions.

Thermal Properties

For all four cases the internal gas temperatures was set to 58.9°C, and the sea water temperature was set to 5.4°C.

The thermal conductivity of the API 5L X65 steel line was set to 45 W/(m·K). The thermal conductivity of the insulation was taken as 0.167 W/(m·K). Based on information related to the outside environment [6], a typical seabed thermal conductivity of 1.1 W/(m·K) was assumed when calculating the heat transfer coefficient into the seabed.

All external and internal surfaces of the thermal FEA model had heat transfer coefficients applied, as shown below in Figure 2 for Run 3 (90° damage case, note that the figure does not show actual model mesh, which is significantly finer).

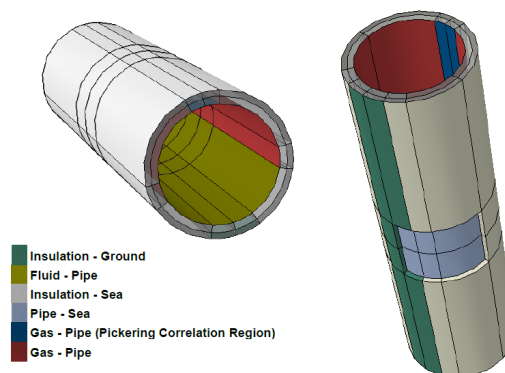


Figure 2: Heat transfer zones applied to the thermal model

Gas to pipe internal walls: The average thermal resistance for the overall system, combined with the gas and internal wall temperatures (all from Flow Assurance Software), allowed the heat transfer coefficient (HTC) from the gas into the wall to be calculated as 1,882 W/(m²·K).

Liquid to pipe internal walls: The HTC from the liquid into the internal wall of the line was determined from standard empirical relationships for turbulent flows in pipes and was calculated to be 909 W/(m²·K).